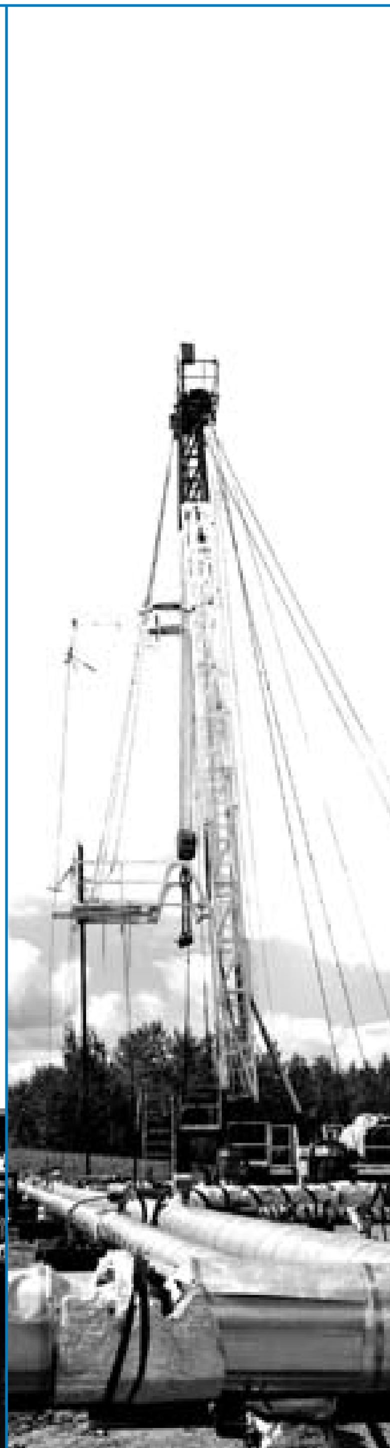
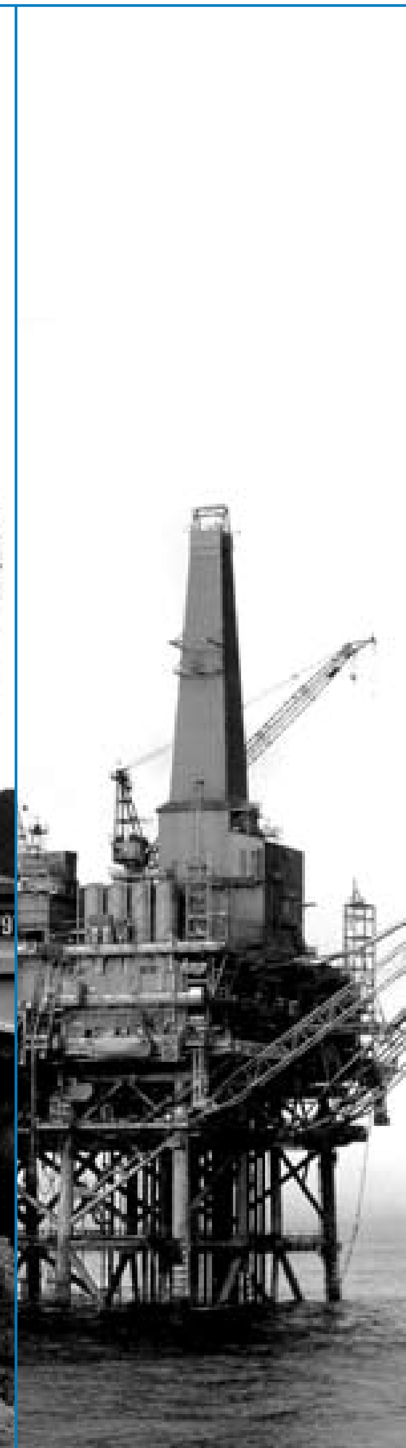
Canadian Natural

THE PREMIUM VALUE DEFINED GROWTH INDEPENDENT





VALUE CREATION ▪ RETURN ON CAPITAL ▪ LOW-COST PRODUCER ▪ RETURN ON ASSETS

general information

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

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	Specific gravity measured in degrees on the American Petroleum Institute scale
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	Extra heavy crude oil, generally more dense than 14° API
C$	Canadian dollars
CAGR	Compound Annual Growth Rate
CAPEX	Capital expense
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse Gas
Horizon Project	Horizon Oil Sands Project
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
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OOIP	Original Oil In Place
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic light crude oil
SEC	US Securities and Exchange Commission
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
USGC	United States Gulf Coast
US$	United States dollars
WCS	Western Canadian Select crude oil blend
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

CAUTIONARY STATEMENTS

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. Please refer to page 40 for the complete special note regarding forward-looking statements.

All production and sales statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel. 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 well head. Methodologies for determining annual reserves are described on pages 34 to 39. This report also includes references to financial measures commonly used in the oil and gas industry that are not defined by Generally Accepted Accounting Principles ("GAAP"). The Company uses these measures to evaluate its performance, however they should not be considered an alternative to or more meaningful than net earnings.

Canadian Natural may disclose contingent resources as additional information. These are internal estimates that utilize the definition within section 5 of the Canadian Oil & Gas Evaluation Handbook as prescribed under NI 51-101. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Additionally engineering and geotechnical appraisal through drilling, testing and/or production is required before the contingent resources can be classified as reserves. There is no certainty that any portion of the resources will be commercially viable to produce.

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

value creation

Canadian Natural's dedicated leadership and disciplined corporate strategy provide a strong foundation for the Company's future and for shareholder value.

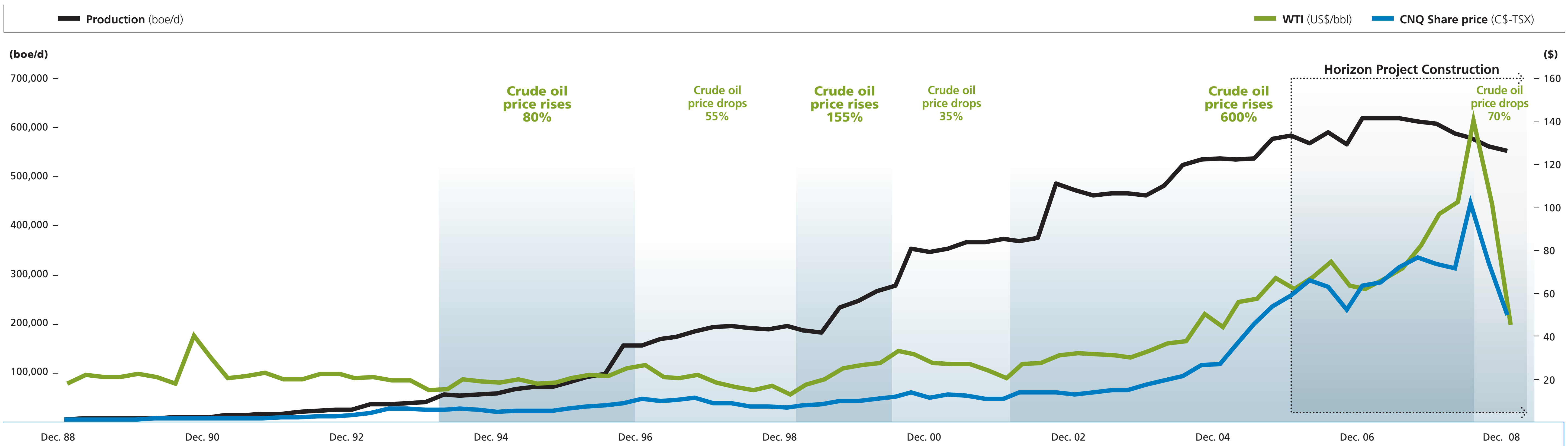
Our objective and strategy have remained consistent over the last twenty years and are as relevant today as they were in the past. The breadth of our asset base provides the Company with the ability to effectively allocate capital to maximize returns.

our business approach

The Company's value creation over the last twenty years was achieved by following some basic principles as articulated below. Maintaining discipline is difficult, but Canadian Natural has proven that it is possible.

- **Drive to be the low cost producer –** this is an important element to the strategy. We strive to be the lowest cost producer in every product and basin in which we operate. Over the long run we believe that only the lowest cost producers will continue to generate economic returns throughout the cycle – the rest will be forced to divest their assets to the stronger competitors. We are a very strong competitor.
- **Focus on exploitation –** we view this as a low-risk approach to value creation as emphasis is placed on maximizing the value of already discovered resource versus trying to find the next major pool. We use proven new technologies, our own discoveries, and new industry findings to effectively "lead the followers". This ever-increasing industry knowledge is maximized across our large developed and undeveloped land holdings, creating even more upside potential.
- **Augment exploitation with strategic acquisitions –** the combination of our lower cost profile and our extensive exploitation-based focused on the basins we operate, make us a natural consolidator of properties throughout our core regions. Often counter-cyclical, our major acquisitions have made us a stronger and more diverse company. Most of these major acquisitions were comprised of a strong footing in our core regions but also provided entry into a new strategic basin.
- **Maintain flexibility and control allocation of capital –** we strive to operate and own 100% of our assets. This allows us to start up or shut down drilling programs on very short notice – facilitating an ever-vigilant weekly allocation of capital by the Management Committee. Simultaneously, when practical we avoid committing ourselves into long term drilling or supply contracts.
- **Strive for balance –** we believe that balance between natural gas, heavy crude oil and light crude oil provide some diversification from commodity price risk while also facilitating more options with which to allocate capital to the highest return projects. Balance between short, medium and long term projects also provides more visibility to future growth initiatives.
- **Maintain financial strength –** maintaining a strong balance sheet and access to capital markets is integral to delivering our plan. We target strong investment grade debt ratings and manage our liquidity as a core asset – particularly important in these current times. We augment these plans with a disciplined hedge program which strives to provide cash flow certainty in the short term, such that the capital plans made by the Company are prudently financeable.

20 years of history



1989

Shallow gas basin of Alberta was the modern iteration of the Company's birthplace and is still a major contributor to our success. Even in today's world, and despite the challenges of Alberta's new royalty framework, conventional and shallow natural gas drilling can generate significant returns as we leverage our strong land position with new technology.

1991

Northeast British Columbia natural gas basin was entered, providing early knowledge and a leading position into this prolific basin. Canadian Natural became a major natural gas producer in British Columbia through acquisition and drilling. Advances in technologies and new resource plays such as Montney Shale gas means that this area will continue to be a major growth driver for the foreseeable future.

1993

Heavy crude oil operations were new to Canadian Natural following the acquisition of primary heavy crude oil lands in 1993. We took our time and developed an expertise in these operations. This allowed us to intelligently acquire and expand our holdings. Today, we are a recognized leader leveraging technology to further grow and recover crude oil. Fields such as Pelican Lake will continue to add significant value to shareholders for years to come.

1996

Thermal heavy crude oil properties were purchased by Canadian Natural. As one of the initial entrants in the field we were better able to understand and economically bid on asset packages including the landmark acquisition in 1999 where the majority of our thermal and Horizon Project mining properties were acquired.
Today we are a leader in thermal crude oil developments and have a clearly defined plan for future growth.

2000

International offshore properties were first acquired as part of a larger transaction. The acquired package included numerous, fractional interests around the world. We carefully rationalized the assets in accordance with our strategy and expertise. The North Sea represents a mature basin where we look to acquire assets and economically extend field lives – the same approach used in Western Canada. Offshore West Africa provides the opportunity for exploration and exploitation growth while leveraging our offshore expertise.

2002

Deep gas basin of Northwest Alberta was initially acquired as part of a larger acquisition and further augmented by other acquisitions. We leveraged our knowledge and expertise between British Columbia and Northwest Alberta to make both areas stronger. Although challenged by Alberta's new royalty framework (which makes many other prospects in this area uneconomic), we are excited about the area's potential. This area is home to numerous resource plays and shale gas opportunities and is a part of our future growth story.

2005

Oil sands mining construction of the Horizon Project began in 2005 with the first phase completed in early 2009. We plan to expand production of this world-class asset base with a target synthetic crude oil rate of 500,000 bbl/d.

Natural gas

A low-risk growth story

With higher returns continuing to be found in crude oil projects, natural gas production for Canadian Natural has declined over the past couple of years. It still remains our largest single product offering, representing 44% of our total oil equivalent production. We balance the development of this low-risk conventional assets with the development of our key growth projects such as the Deep Basin, and the Montney and Muskwa shales.

The development of our assets is based on efficient capital allocation. Therefore, natural gas drilling activity will increase when relative returns and netbacks are equivalent to or better than crude oil.

Thermal heavy crude oil

A visible growth story

Within 13 years of operating experience, Canadian Natural has one of the longest track records of operating thermal properties in Canada. We have an extensive asset base and a disciplined approach to the development of new pools that seeks to minimize geological risk and maximize use of new technologies.

Our extensive asset base will facilitate the eventual development of 285,000 bbl/d of new heavy crude oil over the next several years. We target to develop these assets in an economically prudent and environmentally sustainable way.

Heavy crude oil and Pelican Lake

An exploitation story

As one of the largest heavy crude oil producers in Canada we have a portfolio of conventional assets that provide reliable and sustainable production with good returns on capital.

At Pelican Lake, our polymer flood will add millions of barrels of new reserves at very low development and lifting costs, creating significant value for Canadian Natural's shareholders.

Effective leadership

A story of discipline and experience

The Management Committee exemplifies the maxim that a team can make better decisions than the individual. Capital is diligently allocated based upon returns, time frame, financial capability, marketing and expiries or set-up potential, and other relevant considerations.

Marketing

A story of being proactive

We proactively develop the market. Our first heavy crude oil blending initiative was a major success that allowed more refineries within our existing markets to take our crude oil. Another significant success was expanding heavy crude oil conversion capacity in our geographic markets. We are also expanding our geographic reach via supporting new pipelines, such as the Pegasus and Keystone XL.

Horizon project

A legacy asset for decades to come

The first phase of Canadian Natural's Horizon Project is capable of producing from existing proved and probable reserves for decades. This translates to meaningful generation of cash flow for decades. This "annuity" will fund ongoing growth throughout the Company.

We are evaluating expansions which will lead to approximately 500,000 bbl/d of light, sweet synthetic crude oil production. In all, we believe that up to 8 billion barrels of reserves and contingent resources are recoverable via open pit mining techniques.

International

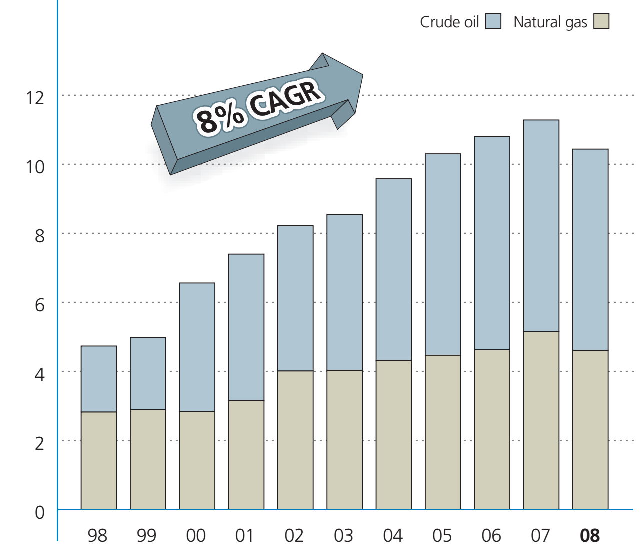
A story of light crude oil growth

With operations in the United Kingdom portion of the North Sea and in Offshore West Africa, we enjoy a stable and committed source of light crude oil production. We continue to develop our international assets with a cautious and cost conscious approach, optimizing facilities and managing our infrastructure. We are utilizing our United Kingdom expertise in our Offshore West Africa development opportunities.

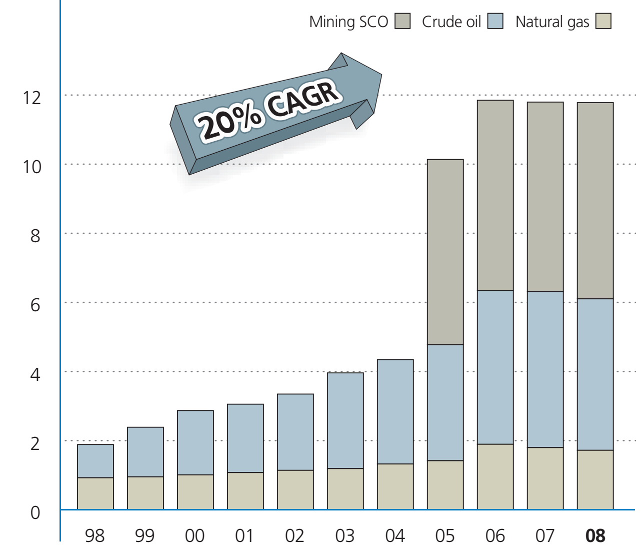
our metrics

The success of our corporate business strategies are measured by **four metrics** that demonstrate consistent performance.

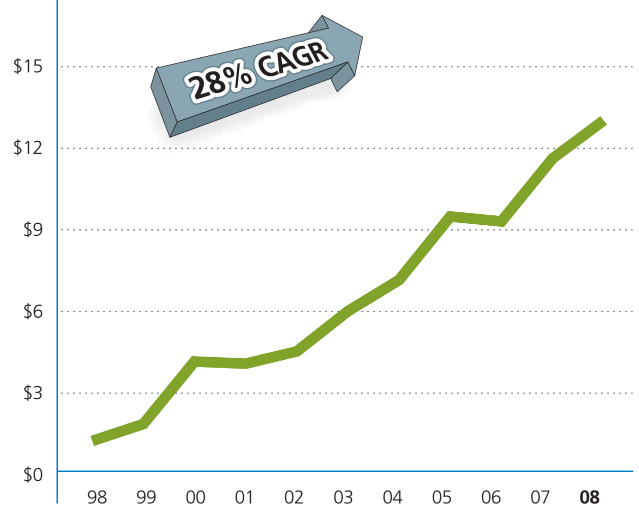
Daily production per 10,000 shares
(boe/d)



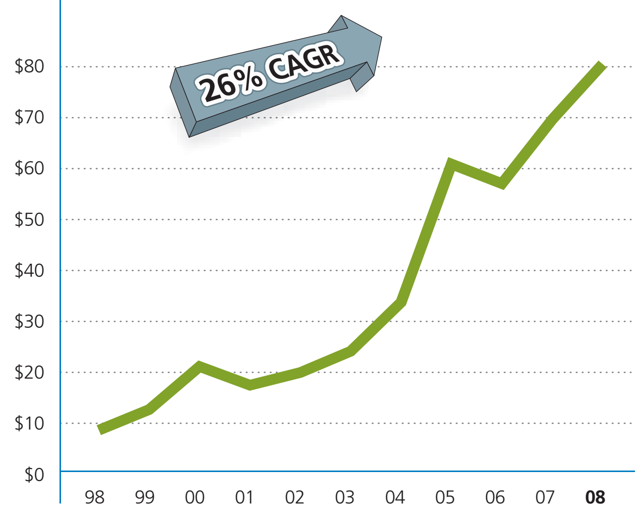
Gross reserves per share (1)
(boe)



Cash flow from operations per share (2)



Conventional pretax net asset value per share (3)



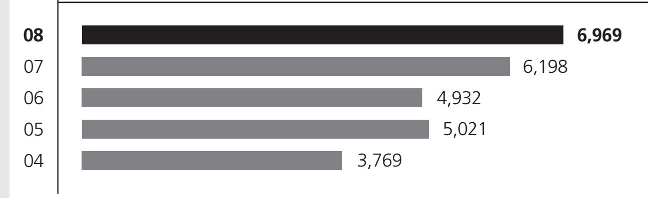
(1) Based on constant price and costs.
(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the MD&A.
(3) Escalated pricing. Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's AIF for conventional reserves, with $250/acre added for core undeveloped land in 2005, 2006, 2007 and 2008, $75/acre for all years prior, less long-term debt and adjustments for working capital. Excludes Horizon Project SCO mining reserves. Refer to the "Year-End Reserves" section of the Annual Report.

performance highlights

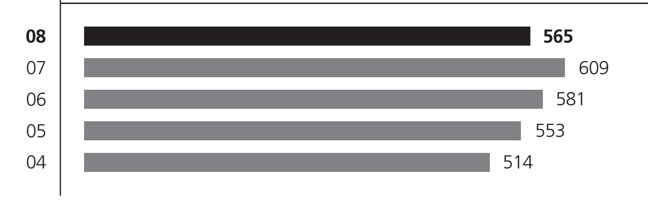
	2008	2007	2006
FINANCIAL ($ millions, except per share data)			
Revenue, before royalties	**$ 16,173**	$ 12,543	$ 11,643
Net earnings	**$ 4,985**	$ 2,608	$ 2,524
Per common share – basic and diluted	**$ 9.22**	$ 4.84	$ 4.70
Adjusted net earnings from operations (1)	**$ 3,492**	$ 2,406	$ 1,664
Per common share – basic and diluted	**$ 6.46**	$ 4.46	$ 3.10
Cash flow from operations (2)	**$ 6,969**	$ 6,198	$ 4,932
Per common share – basic and diluted	**$ 12.89**	$ 11.49	$ 9.18
Capital expenditures, net of dispositions	**$ 7,451**	$ 6,425	$ 12,025
Long-term debt (3)	**$ 13,016**	$ 10,940	$ 11,043
Shareholders' equity	**$ 18,374**	$ 13,321	$ 10,690
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (mbbl/d)			
North America	**244**	247	235
North Sea	**45**	56	60
Offshore West Africa	**27**	28	37
	316	331	332
Natural gas (mmcf/d)			
North America	**1,472**	1,643	1,468
North Sea	**10**	13	15
Offshore West Africa	**13**	12	9
	1,495	1,668	1,492
Barrels of oil equivalent (mboe/d)	**565**	609	581

(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 Management's Discussion and Analysis ("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.

Cash flow from operations
(C$ millions)



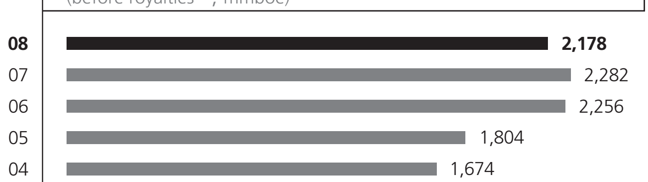
Total production, before royalties
(mboe/d)



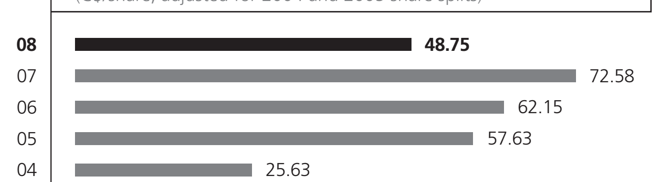
	2008	2007	2006
Drilling activity [1]			
North America	**984**	1,060	1,351
North Sea	**3**	4	8
Offshore West Africa	**3**	4	4
	990	1,068	1,363
Core undeveloped landholdings (thousands of net acres)			
North America	**11,603**	12,160	12,785
North Sea	**258**	287	299
Offshore West Africa	**192**	192	192
	12,053	12,639	13,276
Company gross proved reserves [2] (before royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**1,057**	1,084	1,043
North Sea	**256**	311	299
Offshore West Africa	**157**	148	145
	1,470	1,543	1,487
Conventional natural gas (bcf)			
North America	**4,077**	4,275	4,507
North Sea	**67**	81	37
Offshore West Africa	**107**	79	69
	4,251	4,435	4,613
Barrels of oil equivalent (mmboe)	**2,178**	2,282	2,256
Company net proved reserves [2] (after royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**948**	920	887
North Sea	**256**	310	299
Offshore West Africa	**142**	128	130
	1,346	1,358	1,316
Conventional natural gas (bcf)			
North America	**3,523**	3,521	3,705
North Sea	**67**	81	37
Offshore West Africa	**94**	64	56
	3,684	3,666	3,798
Barrels of oil equivalent (mmboe)	**1,960**	1,969	1,949
Net oil sands proved mineable reserves [2] (after royalties)			
Synthetic crude oil [3] (mmbbl)	**1,946**	1,761	1,596

(1) Excludes net stratigraphic test and service wells.
(2) Based on constant prices and costs.
(3) SCO reserves are based upon upgrading of the bitumen volumes using technologies implemented at the Horizon Project.

Company gross conventional proved reserves
(before royalties [2], mmboe)



Closing TSX share price
(C$/share, adjusted for 2004 and 2005 share splits)



“Our team continually targets cost effective alternatives to develop our portfolio of projects and to deliver our defined growth plan, thereby creating value for shareholders.”

Allan P. Markin
CHAIRMAN
OF THE BOARD

letter to shareholders

Canadian Natural’s goal is to run our business and run it well, executing on our projects and creating value for our shareholders. That is what we have focused on for the past 20 years, and it is what we continue to focus on.

Our world-class asset base is strong and balanced. We have crude oil and natural gas conventional operations in domestic and international basins, along with North America’s most recent oil sands mining operation. We have the depth of knowledge and experience, with the right people in the right place at the right time. Our defined growth plan allows us to create value for our shareholders, even in uncertain economic times.

BUSINESS ENVIRONMENT

2008 was a year characterized by commodity price volatility and uncertainty within the capital markets. During the first half of 2008, crude oil prices reached record levels. By the second half of the year, crude oil pricing faced a massive correction as demand declined worldwide due to the global recession. The year saw a historically narrower heavy crude oil differential, which led to record high netbacks in heavy crude oil – an area where we hold a substantial position in.

Natural gas prices remained relatively weak much of the year, reflecting increased production from the US, along with very high storage levels in both the US and Canada. These volumes were offset slightly by a decline in Canadian natural gas production.

Drilling and service cost pressure did not respond in kind with the weaker relative natural gas pricing and we continued to experience price inflation in the natural gas drilling services sector essentially facing a low price, high cost environment. We also experienced inflationary pressures in the crude oil drilling services sector but these were partially offset – at least for awhile – by strong crude oil pricing.

STRATEGY – OUR APPROACH TO THE BUSINESS

Each phase of the business cycle presents its own unique challenges and rewards. The Company strives to capture opportunity from each one and has been able to grow into a stronger, more robust company as a result. Canadian Natural has a history of value creation as seen through our commitment to growing the four metrics to which we steward – production per share, conventional reserves per share, cash flow per share and conventional pre-tax net asset value per share.

Our approach to our business does not change based on commodity prices or business cycle. It is proven and effective, and serves as a testament to the strength and depth of the Company. Our fundamental approach to business is to maximize value through efficient capital allocation. This is key to our success. Further, we remain balanced in all facets of our business. We balance our product mix with projects in both natural gas and crude oil while balancing project time horizons with near, mid and long-term projects. We achieve production growth through our defined growth strategy, incorporating exploitation and exploration, along with strategic acquisitions. We dominate our core areas through area knowledge, infrastructure and land base, ultimately assisting in cost control. For the vast majority of our assets we own and operate nearly 100% and as such have control over capital allocation.

This year more than ever, our strategy was put to the test and in a challenging and uncertain business environment, it has served us well. This tells us we are taking the right approach.

N. Murray Edwards
VICE-CHAIRMAN
OF THE BOARD

"The economic environment for our Company has changed; however, our flexible approach to capital allocation allows us to take advantage of opportunities that arise, regardless of the business cycle."

NORTH AMERICA CRUDE OIL

Throughout the year we saw great success in North America crude oil, particularly in our heavy crude oil assets. We remain a leading producer of crude oil and NGLs with extensive positions in primary heavy and thermal crude oil production in western Canada and are an industry leader in maximizing netbacks in these areas. We are a low cost producer and are in an enviable position to continue to grow production through our thermal heavy crude oil development plan. We take a measured and methodical approach in the development of these assets and in doing so, we are able to remain cost focused and disciplined in our execution. The economics of this play type remain one of the most attractive in the Company even at lower commodity prices.

As part of our heavy crude oil development plan, the Primrose East expansion was completed in 2008, ahead of schedule and on budget. This 100% owned project added an incremental 40,000 bbl/d of thermal crude oil production capacity to the Company. The robust economics for heavy crude oil carries over into our Pelican Lake assets. The conversion from water flood to polymer flood continued throughout the year as we see enhanced crude oil recovery as the optimal solution for the majority of the reservoir.

Our heavy crude oil production in Western Canada is balanced with light crude oil. We have that expertise and focus on optimizing our light crude oil field operations and water flood techniques. We look to other enhanced oil recovery processes for light crude oil, including CO_2 flooding, polymer flooding and alkaline surfactant flooding. All of these technologies look promising and, we will continue to work to develop these commercial operations.

NORTH AMERICA NATURAL GAS

Canadian Natural holds the largest undeveloped land base in Western Canada with exposure to conventional, unconventional, resource and exploration play types. We are Canada's second largest producer of natural gas with a vast and strategic infrastructure that we leverage to achieve cost control.

Our natural gas strategy is based on allocating capital between low-risk conventional assets and development of new natural gas resources. Conventional exploitation provides low-risk, solid returns and reliable cash flow, and continues to be an important part of our balanced portfolio. However, a large portion of our future resource additions will be sourced from key unconventional projects in our Deep Basin area, along with the Montney and Muskwa shale plays. We are well positioned for short, mid and long-term value growth.

The economics of natural gas continued to be challenging throughout the year, and as near term returns for heavy crude oil projects remain more attractive than natural gas, we will continue to decrease our natural gas drilling program going forward. We will increase production in natural gas when we see economic returns. Our strategy for 2009 is to set ourselves up for the future, countering land expiries and competitive drainage issues with strategic drilling and a focus on reducing costs within the Western Canadian Sedimentary Basin. We have the flexibility to allocate capital and the assets to either slow down or accelerate development, depending on commodity pricing and cost structure.

"Our financial discipline, commitment to a strong balance sheet, and high capacity to internally generate cash flows provide us the means to grow our company in the long term."

John G. Langille
VICE-CHAIRMAN
OF THE BOARD

INTERNATIONAL

Our international assets provide a reliable, low-risk source for continued light crude oil production. We continue to capitalize on our core competency of mature basin exploitation in the North Sea and Offshore West Africa provides development opportunities with significant exploration upside. We capitalize on our relationships that we have developed with stakeholders over the past few years and leverage our technical and operational expertise from the North Sea to our basins in Offshore Côte d'Ivoire and Offshore Gabon.

In the North Sea, we operate 90% of our assets with an average working interest of over 80%. We have expertise in managing aging infrastructure and mature basin exploitation necessary to maximize long-term value creation. We leverage our technical teams in Offshore West Africa where we operate 100% of our assets and have a number of projects under development. In Offshore Côte d'Ivoire at Baobab, we have returned to the field for a one year drilling window to boost production following well failures in 2006. We now have three wells re-drilled with a fourth well underway. At Espoir, we are currently upgrading our FPSO and will continue with an infill drilling program. In Offshore Gabon at Olowi, we are targeting to deliver first crude oil in early 2009 and will continue to drill the remaining wells to reach targeted production.

HORIZON PROJECT – OIL SANDS MINING

The Horizon Project is a world-class asset providing cash flow for years to come. Phase 1 of the Horizon Project includes bitumen mining and an integrated upgrader. Construction on Phase 1 was completed in early 2009 with first production of synthetic crude oil achieved on February 28, 2009 – a historic milestone for Canadian Natural. We faced numerous challenges and inflationary pressures during the planning, construction and commissioning stages of this project. The total construction costs for Phase 1 were approximately $9.7 billion, or $88,182 per flowing barrel of capacity which comes in well below the industry average for current and future projects with similar facilities. First synthetic crude oil was achieved approximately five months beyond the initial target we set upon project sanctioning in 2005. Although the cost and schedule experienced some over run, the first phase of the Horizon Project was built in an extremely volatile and inflationary business environment and in that respect, it is a job well done.

As first crude oil has been achieved, our focus now is on delivering full production capacity for Phase 1 and leveraging our expertise and infrastructure to future expansions. These expansions have been broken out into four tranches or smaller projects that will ultimately lead to enhanced project and cost control. Tranche 1 of the expansion was completed during 2007. Future tranches of the expansion are currently being re-profiled, taking project control to the next level. We will not build future expansions in a high cost environment for a moderate price world.

Steve W. Laut
PRESIDENT &
CHIEF OPERATING OFFICER

"The cornerstone of Canadian Natural's successful strategy is ensuring we are a low-cost producer. This cost advantage, coupled with our diverse portfolio of assets and talented workforce, facilitates strong economic returns for shareholders."

FINANCIAL STRENGTH

As with the rest of our operations, our financial objectives remain the same regardless of business environment – to maintain a strong balance sheet, maintain strong credit ratings, finance operations with a flexible capital structure, and create value. We remain committed to financial discipline and a flexible capital allocation process, developing only those projects with the highest returns. This process leads to a large inventory of high quality opportunities.

Commodity price volatility is a part of the resource industry and as such we protect our cash flow from operations with a risk management program that includes proactively managed commodity price hedging. As a result, we remain flexible regardless of the business cycle and do not compromise our business strategies. Our approach allows us to manage the conditions inherent to the exploration and production business – volatility of commodity prices, demands of the capital markets, ability to capitalize on our asset base and acquisition opportunities.

We are able to generate free cash flow from every one of our business segments and manage our cash flow in a number of ways. A certain amount is required to maintain property and production growth. We focus on managing debt levels to our targets and returns to our shareholders. And lastly, we continue to develop our significant and diverse asset base providing for long-term growth.

We increased our dividend in 2008, the ninth consecutive year. This recognizes the stability of our cash flow and ensures a cash return to our shareholders.

THE CANADIAN NATURAL ADVANTAGE

We control the allocation of our capital and remain disciplined. Our management philosophy is strong and balanced, just as the rest of our business. Going forward, we will capture opportunities and create value through this challenging part of the business cycle. We have done it in the past and we will do it again.

We are in a position that allows us to be flexible due to our extensive land base and inventory of prospects in both crude oil and natural gas. Our strategy allows us to prepare for the future. As we have said time and again, all assets end up in the hands of the low-cost producer and in tough economic times, the low-cost producer has the advantage. It is no coincidence that Canadian Natural is a low-cost producer. We have that advantage.

Allan P. Markin
CHAIRMAN
OF THE BOARD

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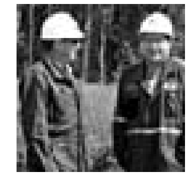


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Allan Stella, Robert Stelten, Peter Stephen, Taryn Stephenson, Jane Stevens, Lyle Stevens, James Stevenson, Robert Stevenson, Robert B Stevenson, Carol Stewart, Cody Stewart, Douglas Stewart, Karen Stewart, Lorie Stewart, Rory Stewart, Wendy Stewart, Rick Stieben, Kevin Stilwell, Stewart Stirling, Melissa Stockes, Mark Stockton, Shaun Stokes, Didier Stout, Suzanne Strachan, Wade Strand, Robert Strang, Linda Strangway, Tanner Strangway, George Stratford, Brenda Stratichuk, Michael Street, William Stretch, Darcy Stringer, Michael Stroh, Robert Struski, Dwayne Strynadka, Linda Stuart, Peter Stuart, Allan Stubel, SueAnn Stuckey, Christopher Study, Mike Sturkenboom, David Sturrock, Ravi Subramaniam, Stephen Suche, Chris Suhan, Mark Sullivan, Shelley Sullivan, Victoria Sullivan, Shiraz Sumar, Effie Summers, Daniel Sutherland, Rick Sutton, Scott Sverdahl, Rade Svorcan, Amer Swadi, Steven Swain, Christine Swan, Stephen Sweetapple, Nathan Swennumson, Halina Swierz, Paul Swire, Edward Switzer, 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world-class assets

Canadian Natural's strong, low-risk asset base includes natural gas and crude oil properties, highlighted by world-class oil sands in-situ and mining developments.

CREATING VALUE: DEFINED STRATEGY

Canadian Natural's strategy is based on allocating capital to maximize returns. This is achieved through effective execution by being proactive and recognizing and capturing opportunities. The Company dominates its core areas and maintains high levels of ownership and operatorship for all of its properties. This allows for cost control, flexibility and efficient decision making. We are the drivers of our own destiny.

Balance is a key part of our approach to business. The Company maintains balance in its product mix, producing both natural gas and crude oil. We balance our project time horizons between near, mid and long-term projects. Finally, we balance organic growth with growth through acquisition.

We focus on long-term value creation through our defined plan for profitable growth. We have extensive knowledge and experience in mature basin exploitation, utilizing our expertise in all of the basins in which we operate, whether it be the Western Canadian Sedimentary Basin ("WCSB"), the North Sea or Offshore West Africa.

NORTH AMERICA

2008 net, after royalties	Production (mboe/d)	Proved reserves (1) (mmboe)
Crude oil and NGLs	208	948
Natural gas	204	587
Boe	412	1,535
% of total	85	78

INTERNATIONAL

2008 net, after royalties	Production (mboe/d)	Proved reserves (1) (mmboe)
Crude oil and NGLs	68	398
Natural gas	4	27
Boe	72	425
% of total	15	22

HORIZON PROJECT MINING

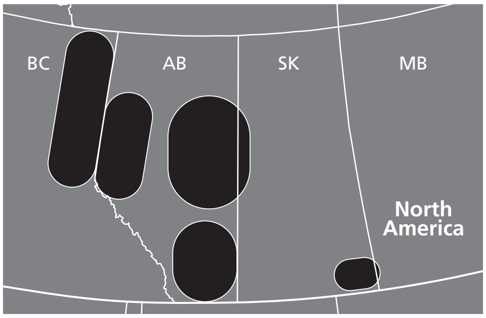
2008 net, after royalties	Proved reserves (1) (mmbbl)
Synthetic crude oil (2)	1,946

(1) Based on constant prices and costs.
(2) SCO reserves are based upon upgrading of the bitumen volumes using technologies implemented at the Horizon Project.

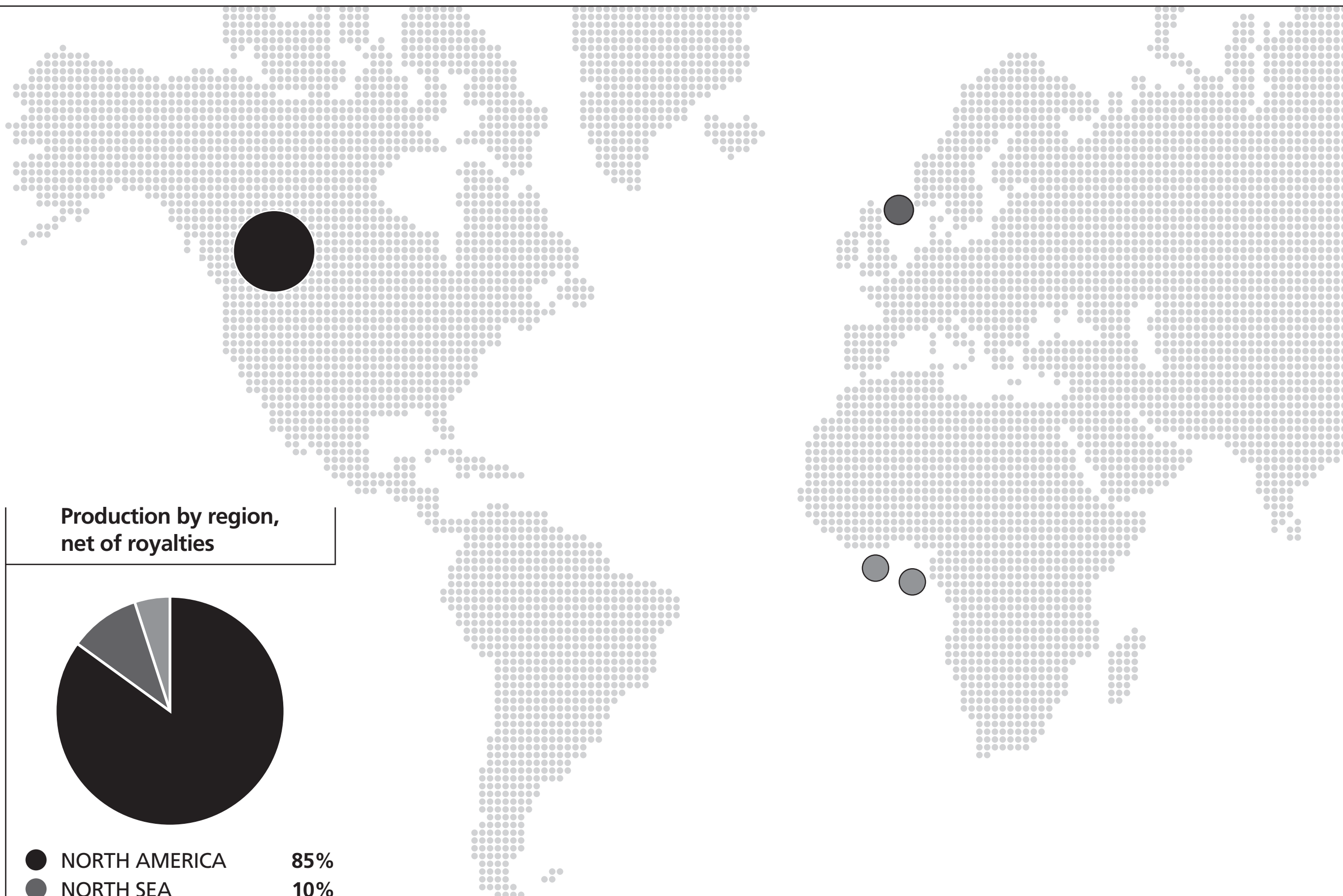
North America

Canadian Natural's North American operations serve as the foundation for the Company, with a balanced portfolio of assets, providing low-risk, sustainable and economic production.

- Canadian Natural has the largest undeveloped land base in the WCSB and a large infrastructure position.
- We have exposure to major natural gas resource plays in the WCSB and balance the development of new natural gas resources with the development of low-risk conventional assets.
- We are one of the largest producers of conventional crude oil and NGLs in Western Canada, and have 285,000 bbl/d of incremental crude oil projects to develop from our thermal heavy crude oil asset base.
- The Horizon Project includes a surface oil sands mining and bitumen extraction plant, complimented by on-site bitumen upgrading and associated infrastructure. The Horizon Project produces high quality synthetic crude oil.



Allan M. Knight
SENIOR VICE-PRESIDENT,
INTERNATIONAL & CORPORATE DEVELOPMENT



Production by region, net of royalties

NORTH AMERICA	**85%**
NORTH SEA	**10%**
OFFSHORE WEST AFRICA	**5%**

North Sea

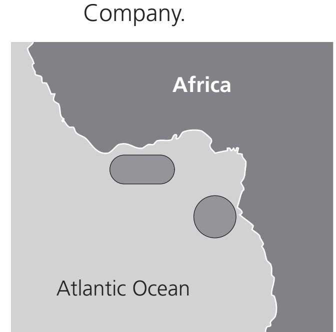
Canadian Natural's core competency in the UK portion of the North Sea is managing existing infrastructure and extending field life in a mature basin.

- A source of high value, light crude oil with long-term developments.
- Capitalize on core competency of mature basin exploitation.

Offshore West Africa

Canadian Natural's competitive advantage in Offshore West Africa lies in the relationships the Company has built with the stakeholders of Côte d'Ivoire and Gabon.

- Generates significant free cash flow providing light crude oil growth.
- Provides some of the highest returning projects in the Company.



operations defined

PRODUCTION

As commodity and market prices fluctuate, Canadian Natural's approach to business remains consistent. The strength of our strategy was demonstrated throughout 2008, as a volatile and uncertain business environment put the industry to the test. We continue to maintain balance within our portfolio of assets, project time horizons and production growth. We take a cautious approach in developing our assets and maintain large project inventories in both natural gas and crude oil. As a result, we have the ability to high grade projects, to develop and produce those assets that yield the highest returns. Canadian Natural allocates capital to maximize returns amongst the commodities we produce (i.e. natural gas, light crude oil, Pelican Lake crude oil, primary heavy crude oil, thermal crude oil, and synthetic crude oil ("SCO") from oil sands mining). Time and resources are allocated towards those projects that give the greatest economic return. Canadian Natural has a proven track record based on low-risk, exploitation based production. Most importantly, we control our costs through area knowledge and domination of our core areas.

During 2008, production before royalties was 565 mboe/d, a slight decline from 2007 levels of 609 mboe/d. The decline in production resulted from Canadian Natural's strategic decision to reduce spending on natural gas drilling. Natural gas production, before royalties, for the year averaged 1,495 mmcf/d, down 10% from 2007. Crude oil volumes for 2008 were down averaging 315,667 bbl/d for the year, a decrease of 5%. The decrease in crude oil was a result of natural declines in primary crude oil drilling, strategically reduced activity in the North Sea, and the nature of the steaming cycle in thermal crude oil operations.

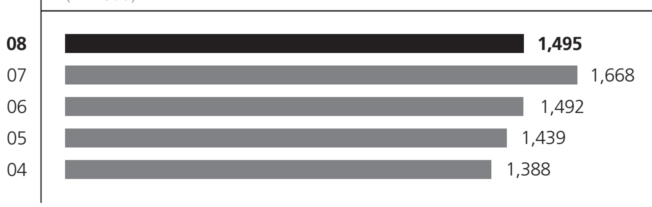
STRATEGIC LAND BASE

Canadian Natural has the largest conventional undeveloped land base in the WCSB, with undeveloped net acreage of 11.5 million acres. The strength and depth of Canadian Natural's land base is a result of continued land purchases and utilizes strategic acquisitions. Our land base affords significant opportunities to control operating costs, along with finding and on-stream costs. The majority of the Company's land base is positioned to utilize existing owned and operated infrastructure and also strategically positions Canadian Natural to maximize the benefit of new play types developed by ourselves and industry.

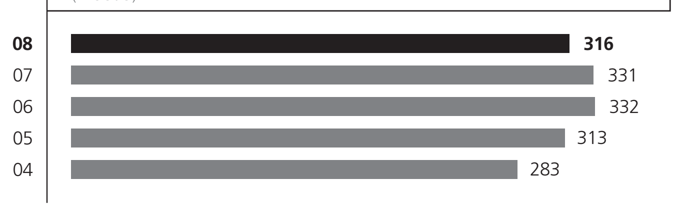
The infrastructure associated with our land base also provides a competitive advantage in terms of lowering marginal operating and development costs for newly drilled or acquired properties. This dominance can create acquisition opportunities as we control access to strategic infrastructure and maintain a low-cost regime.

	2008		2007	
(before royalties)	**Production mboe/d**	**Mix %**	Production mboe/d	Mix %
Natural gas	**249**	**44**	278	45
North America light/medium crude oil and NGLs	**53**	**9**	57	9
Pelican Lake crude oil	**37**	**6**	34	6
Primary heavy crude oil	**89**	**16**	92	15
Thermal heavy crude oil	**65**	**12**	64	11
North Sea light/medium crude oil	**45**	**8**	56	9
Offshore West Africa light/medium crude oil	**27**	**5**	28	5
Total	**565**	**100**	609	100

Daily natural gas production, before royalties
(mmcf/d)



Daily crude oil and NGLs production, before royalties
(mbbl/d)



Mary-Jo E. Case
VICE-PRESIDENT,
LAND

CORE LANDHOLDINGS

(thousands of acres)	2008 Gross	2008 Net	2008 Net %	2007 Gross	2007 Net	2007 Net %
North America						
Developed	**8,524**	**6,640**	**78**	8,255	6,424	78
Undeveloped	**14,033**	**11,603**	**83**	14,782	12,160	82
	22,557	**18,243**	**81**	23,037	18,584	81
North Sea						
Developed	**108**	**74**	**69**	122	88	72
Undeveloped	**314**	**258**	**82**	356	287	81
	422	**332**	**79**	478	375	78
Offshore West Africa						
Developed	**7**	**4**	**57**	7	4	57
Undeveloped	**247**	**192**	**78**	247	192	78
	254	**196**	**77**	254	196	77
Total						
Developed	**8,639**	**6,718**	**78**	8,384	6,516	78
Undeveloped	**14,594**	**12,053**	**83**	15,385	12,639	82
	23,233	**18,771**	**81**	23,769	19,155	81

GEO-SCIENCE STRATEGY

The integration of seismic interpretation, geology, and innovative engineering drives our successful annual drilling program and our ongoing addition of new high quality locations to our conventional and unconventional inventory. We believe that a multi-disciplined focus on geology, geophysics and reservoir engineering reduces exploration risk while enhancing capital efficiency, ultimately leading to improved full cycle economics. In total, we invested $55 million during 2008 to acquire new seismic and to purchase and reprocess existing seismic data. In total, 1,113 kilometers of conventional 2D seismic data and 200 square kilometers of 3D seismic data were acquired. Additionally, 4,970 kilometers of conventional 2D seismic data and 1,027 square kilometers of 3D seismic data were purchased. We continue to acquire this data under stringent environmental controls and in a cost effective manner.

ACTIVITY BY CORE REGION

	Net Undeveloped Land (thousands of net acres)		Drilling Activity (net wells)	
	2008	2007	**2008**	2007
North America conventional				
Northeast British Columbia	**2,227**	2,401	**27**	61
Northwest Alberta	**1,352**	1,489	**82**	126
Northern Plains	**6,452**	6,626	**643**	636
Southern Plains	**832**	925	**112**	169
Southeast Saskatchewan	**130**	121	**58**	28
Thermal in-situ oil sands	**495**	483	**99**	192
	11,488	12,045	**1,021**	1,212
Horizon Oil Sands Project	**115**	115	**92**	98
North Sea	**258**	287	**4**	7
Offshore West Africa	**192**	192	**4**	5
	12,053	12,639	**1,121**	1,322

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

Randall S. Davis
VICE-PRESIDENT,
FINANCE & ACCOUNTING

DRILLING ACTIVITY AND STRATEGY

During 2008, Canadian Natural successfully drilled 682 net crude oil wells and 269 net natural gas wells. It was an uncertain and volatile year for commodities with the price of crude oil steadily escalating, reaching record highs by mid year, followed by dramatic weakening concurrent with the global economic downturn and uncertainty surrounding worldwide demand for crude oil. For the year, natural gas prices remained weaker relative to crude oil prices. As such, capital continued to be allocated towards higher return crude oil projects, in particular, heavy crude oil. The crude oil focus of Canadian Natural's drilling activity for 2008 was a reflection of historically narrow heavy crude oil differentials. For the bulk of the year, returns in heavy crude oil exceeded returns elsewhere in the Company. Counter to the strong heavy crude oil differential, the weaker natural gas price throughout much of the year led to declines in natural gas production and a decrease in overall natural gas wells drilled.

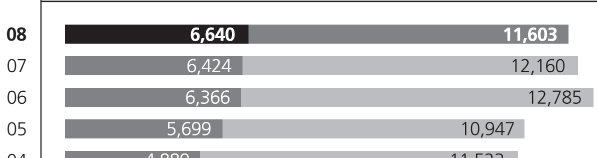
In 2008, we saw stabilization and in some cases a reduction of industry and service costs within the WCSB. Small decreases in cost were seen in natural gas drilling in certain geographic areas. The stabilization was in response to industry-wide pressure placed on the services through several scaled-back drilling programs, weaker commodity prices and uncertainty surrounding Alberta's new royalty framework. Looking specifically to natural gas, efficiencies were gained and our natural gas drilling program, although scaled back, returned results that exceeded expectations – a result of better crews, better equipment and a deep, high quality prospect inventory. Costs in crude oil related services stabilized but continue to be high.

Going forward, 2009 will be a year where Canadian Natural will benefit from its capital allocation flexibility. Natural gas drilling will focus on the development of strategic projects and land expiries. The level of crude oil drilling will be reduced but closer to 2008 levels as strong returns are achievable, largely driven by strong heavy crude oil differentials. We will be prudent in our approach to developing our assets. Flexibility is the key and we are able to ramp up or scale back our programs quickly and efficiently.

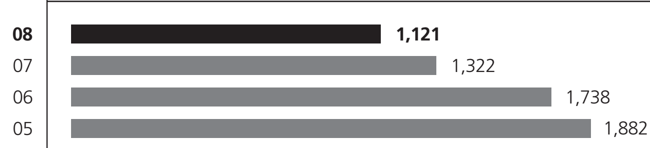
WELLS DRILLED

Year ended December 31	**2008**			2007	
	Gross	**Net**	**Success**	Net	Success
Crude oil – North America					
Light crude oil	**115**	**98**	**93%**	63	94%
Pelican Lake crude oil	**110**	**110**	**100%**	126	99%
Primary heavy crude oil	**422**	**396**	**95%**	340	94%
Thermal heavy crude oil	**74**	**74**	**100%**	55	100%
North Sea light crude oil	**3**	**2**	**76%**	4	100%
Offshore West Africa light crude oil	**4**	**2**	**100%**	4	100%
	728	**682**	**96%**	592	96%
Natural gas – North America					
Northeast British Columbia	**28**	**24**	**88%**	42	74%
Northwest Alberta	**79**	**66**	**95%**	98	88%
Northern Plains	**145**	**100**	**96%**	96	72%
Southern Plains	**159**	**79**	**100%**	147	99%
	411	**269**	**96%**	383	85%
Dry	**44**	**39**		93	
Subtotal	**1,183**	**990**	**96%**	1,068	91%
Stratigraphic test / service wells	**133**	**131**		254	
Total	**1,316**	**1,121**		1,322	

Total North America landholdings
(thousands of net acres)



Total wells drilled
(net wells)



north america natural gas

Canadian Natural is the second largest producer of natural gas in Western Canada with average daily production of 1,472 mmcf/d for 2008. Natural gas remains our single largest product offering, representing 44% of our total oil equivalent production. Our natural gas assets are strong, leveraged by a vast land base, well developed infrastructure and a deep, diversified inventory of drilling prospects. By utilizing our expertise, infrastructure and low cost operations, we have the competitive advantage to achieve low-risk growth.

2008 proved to be another challenging year for natural gas with relatively flat pricing while industry costs continued to rise. With higher returns found in crude oil, capital was allocated away from natural gas towards the crude oil projects. This resulted in a decline in production volumes of 10% from entry to exit for the year. In light of a reduced natural gas drilling program, we were able to focus on only the most economic natural gas wells and as such, executed a high-graded drilling program. This allows us to control our costs while exceeding performance targets for the year. Although the year was not easy for natural gas, we made steady, significant progress in the development of our key growth projects, namely the Deep Basin and shale plays. We have exposure to several major resource plays in the WCSB and are delivering our future resource potential in a cost effective manner.

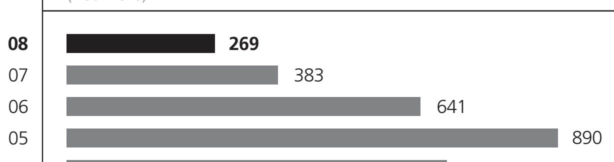
The approach to developing our natural gas assets will continue to be based on efficient capital allocation in 2009. We will balance the need for capital between low-risk conventional assets which provide a source of low-risk and reliable cash flow, with the development of new natural gas resources. As netbacks increase in natural gas, so too will our drilling activity. The priorities for the year are to advance our resource projects, to grow our location inventory and to effectively execute on our drilling program. Our program includes drilling strategic wells to offset expiries on lands located in our growth areas.

Our natural gas production is concentrated in five North American core regions: Northwest Alberta, Northeast British Columbia, the Foothills, the Northern Plains and the Southern Plains. These areas are anchored by our large strategic infrastructure ensuring cost-effective development of all our key projects. This infrastructure is throughout our land base of over 11 million net acres of undeveloped land.

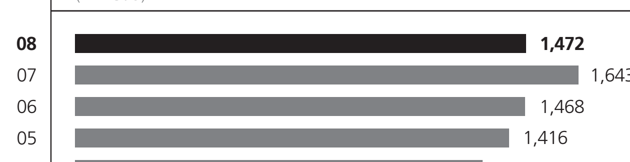
NORTHWEST ALBERTA

Canadian Natural has transformed the potential of the deep multi-zone plays of Northwest Alberta into a widespread, repeatable production project. Again, we enjoy a large undeveloped land base of 1.4 million net acres in conjunction with 26 operated facilities and an extensive pipeline network that provides significant competitive advantage. We have leveraged our existing land and infrastructure to expand the initial Cardium play into our current multi-zone play. In Wild River, we have achieved sustainable cost control by reducing the number of drilling days per well and now routinely commingle up to 12 geological zones, decreasing the average cost of completion per zone by as much as 50% through limited entry fracs. Most notably, we have increased the reserves per well while reducing the cost to drill new wells.

North America successful natural gas wells drilled
(net wells)



North America natural gas production, before royalties
(mmcf/d)



Jeff W. Wilson
SENIOR VICE-PRESIDENT, EXPLORATION

In the Deep Basin our Lower Doig/Montney resource project is similar in many ways to the Wild River area. Again, we are using our land and infrastructure to reduce the cost of entry into this emerging resource play. Our initial position in the Montney was greatly enhanced by the timely acquisition of Anadarko Canada in late 2006. We capitalized on our existing land position at that time, giving us early exposure to the play. This allowed us to acquire strategic sections of prime Montney land at a fraction of today's cost.

NORTHEAST BRITISH COLUMBIA

Canadian Natural is the second largest holder of undeveloped land in British Columbia. Along with lowering and controlling our costs, this land position combined with our extensive infrastructure allows for low cost entry into the overheated market for natural gas resources, most notably in the Montney shales.

The progress we have made in the Deep Basin Lower Doig/Montney play continues into our Northeast British Columbia Montney project at Septimus, which is currently in the pilot phase. We have gathered geo-data and production test data and have wells planned for 2009 setting up our commercial development phase, targeted for 2010. Going forward, we will maximize our cost effective position by integrating the data with the right technology, and acquire new land and assets that fit our existing infrastructure.

The Helmet area of Northeast British Columbia has a play that contains significant thicknesses of natural gas pay in the Muskwa shale. Based on existing data, our strategic land position and our Jean-Marie infrastructure, we have allocated long-term capital to the experimental stage of this project. We will further evaluate the Muskwa potential by drilling more wells on our existing land and production testing through existing facilities to determine if a viable development exists.

FOOTHILLS

The Foothills area has a large inventory of development and exploration ready to drill prospects. We also have the land, infrastructure and expertise to exploit the large undiscovered remaining resources. We will continue to build our drilling location inventory that has resulted in 14% average annual growth since 2004.

NORTHERN / SOUTHERN PLAINS

In the Plains natural gas area, shallow gas and Horseshoe Canyon coal bed methane ("CBM") provide large, downspaced drilling programs that result in low-risk, long life reserves. In addition, ongoing focused exploitation continues to find excellent multizone, conventional prospects for development drilling and secondary zone recompletions. Overall, natural gas production from CBM and shallow gas has not been as severely impacted by Alberta's new royalty structure and will provide opportunities for timely drilling programs as prices improve.

Canadian Natural continues to access and develop new natural gas opportunities, focus on growing our location inventory and optimizing all our natural gas production assets throughout 2009.

north america crude oil and NGLs

Canadian Natural is one of the largest conventional producers of crude oil and NGLs in western Canada, with approximately 244,000 barrels per day production of crude oil and NGLs in 2008. Our crude oil assets illustrate Canadian Natural's balanced portfolio approach to business, producing light, Pelican heavy, primary heavy and thermal heavy crude oil. Canadian Natural's crude oil is produced from very distinct assets, using different recovery technologies that are tailored to fit each unique reservoir.

In 2008, we saw significant progress in the development of our North American crude oil assets. The completion of the Primrose East expansion project was a highlight, adding an incremental 40,000 barrels per day of capacity to our thermal operations. We also saw the continuation of the Pelican Lake enhanced crude oil recovery program. Primary heavy crude oil production, which serves as the backbone for all our crude oil assets, continued to deliver low-risk, reliable production.

Going forward we will achieve production growth from crude oil through our defined growth strategy incorporating low-risk development projects. We target secondary and tertiary recovery of light crude oil, primary, secondary and tertiary recovery of heavy crude oil and thermal recovery of bitumen. Our crude oil development strategy is based on low-risk exploitation anchored by our expertise in improved recovery techniques. This allows us to maximize crude oil recovery and value from both mature and new crude oil pools.

LIGHT CRUDE OIL AND NGLS

We produce light crude oil and NGLs in all of our western Canadian core regions. The majority of these pools are mature but recovery factors are still modest. The majority of Canadian Natural's light crude oil pools are produced under waterflood which provide relatively high ultimate recovery factors with low production decline rates. All of these projects are low risk but do require rigorous geological and engineering analysis in order to be successful.

Although the basin is mature, new pool development remains part of our light crude oil strategy. Our extensive undeveloped land base continues to deliver new pool discoveries through detailed geophysical and geological analysis.

Our light crude oil pools have recovered approximately 30% of the original oil in place ("OOIP"), leaving a significant resource target. The availability and development of new technology leads to improving recovery factors, adding significant leverage to Canadian Natural. We are currently testing various EOR processes that include water flooding, CO_2 flooding, polymer flooding and alkaline surfactant polymer flooding. All of these technologies show promise.

In 2008, Canadian Natural's light crude oil drilling and development programs continued to pursue several initiatives within Western Canada. We efficiently executed on low-risk, infill and step-out drilling in crude oil pools located in the core regions of Northern and Southern Plains, Northwest Alberta, Northeast British Columbia and Southeast Saskatchewan. Our strong technical teams continued with waterflood optimization programs through detailed reservoir characterization and analysis. EOR made progress with continued testing and evaluation with the promise of commercial projects in the near future.

Canadian Natural drilled 105 wells in our light crude oil program during 2008. For 2009, we are planning to drill 20 wells in our light crude oil program across western Canada.

Tim S. McKay
SENIOR VICE-PRESIDENT, OPERATIONS

PELICAN LAKE CRUDE OIL

Pelican Lake is a premium asset within Canadian Natural's portfolio, producing approximately 37,000 barrels per day in 2008. We have had great success with EOR in this pool, first with waterfloods and now with polymer floods.

Pelican Lake is a large, shallow crude oil pool in our Northern Plains core region estimated to contain 4.5 billion barrels of OOIP on Canadian Natural land. Although initially developed for primary production, we started converting portions of the field to water flood in 2004, resulting in a significant production increase which reversed the previous three years of production decline. Building on that success, we began testing polymer flooding in 2005. This EOR technique has proven to be much more effective than waterflooding and as such, we are in the midst of converting more of the field to polymer flood.

Polymer is a chemical compound that we mix with water to create an injection that has a viscosity similar to olive oil. The application of the polymer flood increases oil recovery since the thicker polymer solution reduces fingering or break-through in the reservoir. Polymer flooding has the potential to increase ultimate recovery to 20% of the OOIP at a relatively low cost; approximately an incremental \$0.40 to \$0.60 per barrel in operating cost plus an incremental \$6 to \$8 per barrel of reserves in capital cost.

During 2008, Canadian Natural drilled 110 wells as part of our Pelican Lake program. Since converting from primary production to the polymer flood requires us to re-pressurize the reservoir with the polymer solution, the full response from the polymer flood is not expected until 2010. Production is expected to peak in 2011 and plateau for several years at over 50,000 barrels per day.

As in any waterflood, optimizing water handling is key to the process – polymer flooding is no different. We recycle more than 90% of our produced water, and we have initiated brackish water usage to mix with the polymer. We have been operating in the area for more than 10 years and our staff has done a tremendous job adapting to new technology while minimizing our operating and capital costs.

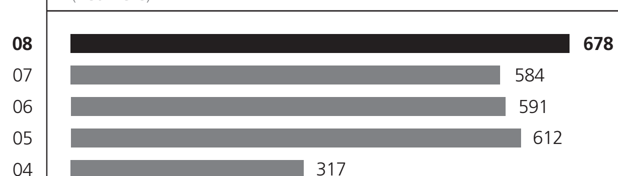
For 2009, we continue to work on enhancements to the process to optimize our field operations. We are testing the polymer flood in regions with poor crude oil quality and continue to optimize the quantity and type of polymer we use. Improvements to our facilities design have been made and we are now building larger mixing units and are enhancing our polymer distribution system.

PRIMARY HEAVY CRUDE OIL

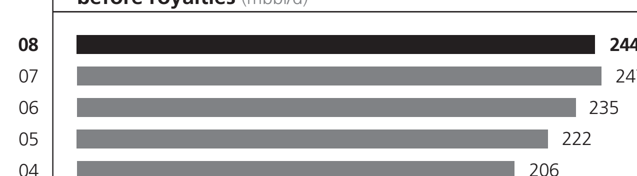
Canadian Natural's primary heavy crude oil operations are centered on the Alberta – Saskatchewan border, near the city of Lloydminster. In 2008 we produced approximately 90,000 barrels per day of heavy crude oil from our extensive and dominant land base. This dominance allows us to conduct large scale drilling and development programs while minimizing our capital cost requirements. Costs are further managed through owning and operating centralized treating and sand handling facilities, maximizing their utilization and using our size to achieve economies of scale. Our infrastructure includes five crude oil processing facilities and four salt caverns for solids disposal. Ownership of the ECHO sales pipeline allows us to be the only producer capable of delivering undiluted heavy crude oil into our blending facilities at Hardisty, Alberta. Our infrastructure and size gives us a significant competitive advantage in this area and our large inventory of drilling prospects leads to greater flexibility enabling us to react very quickly to changes in commodity prices or changes in capital allocation.

Primary production typically produces between 5% and 15% of the OOIP, leaving a vast unrecovered resource that we feel will ultimately be exploited. Improving recovery by drilling infill wells in some pools, testing waterfloods in others, and using horizontal

North America successful crude oil wells drilled
(net wells)



North America crude oil and NGLs production, before royalties (mbbl/d)



wells in specific applications, are a few of the ways we are working towards improving recovery factors. We are also evaluating several other technologies, such as polymer flooding and solvent injection.

During 2008 we drilled 415 low-risk heavy crude oil wells and recompleted approximately 490 wells to secondary zones. For 2009, 317 heavy crude oil locations are forecast to be drilled and a further 380 wells are targeted to be recompleted.

THERMAL (IN-SITU) HEAVY CRUDE OIL

Canadian Natural believes it holds some of the best oil sands assets in Canada, providing tremendous value and growth potential. Our thermal assets are located in two of the major oil sands deposits in Western Canada – the Athabasca and the Cold Lake deposits. Within the Athabasca deposits, the McMurray reservoir is our primary target and steam assisted gravity drainage ("SAGD") is the recovery process of choice. SAGD uses two well bores, one for continuous steaming and the other for continuous production. Within the Athabasca region, the majority of our assets are in the planning stages. These include Kirby, Grouse, Birch Mountain, Ipiatik, Gregoire and Leismer. In the Cold Lake deposits, we have our Primrose and Primrose East operations where we currently produce from the Clearwater reservoir using the cyclic steam stimulation ("CSS") process. CSS uses a single well bore to inject and produce steam. This technology has been historically applied to reservoirs that have barriers to vertical flow. The production peaks and troughs at Primrose are a reflection of the cyclic steam process – the peaks are associated with production cycles from newer, less mature wells and the troughs are associated with production cycles from the more mature areas in the field. In 2008, production from our thermal operations averaged 65,000 bbl/d.

Canadian Natural's multi-year thermal development program continued in 2008 with the completion of construction and commencement of production at the Primrose East expansion. This 40,000 bbl/d project achieved first production in Q4/08, on budget and ahead of schedule. The major components to the project included expansion of our central treating facility at Wolf Lake, taking capacity to 120,000 bbl/d, and also a new satellite steam generation facility at the Primrose East site. We also drilled 80 horizontal wells from four pads for the first stage. The development, design and construction of Primrose East has proven to be a success.

Throughout 2008 and into 2009, we will drill additional well pads at Primrose North which will result in production increases. We will also continue development of the existing operations at Primrose South and North with the drilling of 70 wells.

The next thermal project that Canadian Natural has under development is Kirby. It is the first project that we are undertaking in the Athabasca – McMurray reservoir and will be using SAGD technology. Regulatory applications were filed in 2007.

Beyond 2009 we see the potential to add significant incremental thermal in-situ production from our oil sands leases. By executing our defined plan to develop these leases and assuming adequate returns are achievable, we target to achieve 15% growth on our thermal production alone. Our thermal operations represent a tremendous value growth opportunity and are an integral part of Canadian Natural's defined plan.

international

International operations remain a strategic part of our business, providing a stable and committed source of light crude oil production. We concentrate our efforts in two core areas, the UK portion of the North Sea and in Offshore West Africa. We are able to apply our expertise in mature, low-risk, exploitation basins to our North Sea operations, leveraging our experience to add value through our Offshore West Africa assets. As part of our fundamental strategy, we maintain high working interest in all of our International assets.

In the North Sea, attention is focused on managing existing infrastructure in a mature basin which leads to field life extension. With a solid inventory of drilling prospects, the North Sea provides additional recovery potential in a low-risk environment. In Offshore West Africa, the Company has some of its highest returning projects. Offshore West Africa assets continue to generate significant free cash flow as they provide considerable light crude oil growth.

UNITED KINGDOM SECTION OF THE NORTH SEA

In the UK portion of the North Sea, our focus is on managing our infrastructure, platform maintenance and mature basin exploitation. This approach ultimately prolongs the life and economic value of our assets. The North Sea is a low-risk source of high-value, light crude oil. We maintain a large inventory of drilling locations to maximize our development projects and infill drilling. We operate 90% of our fields in the North Sea with an average working interest of over 80%, giving us control of our assets.

During 2008, we saw high production uptimes with top quartile performance for our assets. We delivered key production enhancements and field life extension projects while drilling four net wells, three workovers, and increasing water injection at our Columba E North Sea development. The majority of our production is achieved by optimizing water injection and processing as many barrels of crude oil as possible. We also executed five planned turnarounds as part of our advanced asset integrity management program aimed to enhance the long-term viability of our infrastructure.

For 2009, we are consistent with our defined strategies. Very few wells will be drilled during the year as projects have been deferred, though we maintain a very strong inventory of drilling prospects for resumption of activity when appropriate. Capital cost and operating cost reduction are paramount for 2009. Focus will remain on cost reduction projects and upgrades to facilities to add long-term value, with three major turnarounds planned. As a result of deferred drilling and turnarounds, production will be down slightly for the year.

Long term, our objective for the North Sea is to stabilize production and plan for modest growth with long-term developments of Lyell, Columba and Thelma. Mature field declines will be offset with development projects and infill drilling. We also expect there may be significant acquisition opportunities within the basin where we could capitalize on our mature basin expertise.

Terry J. Jocksch
VICE-PRESIDENT, INTERNATIONAL
& MANAGING DIRECTOR
CNR INTERNATIONAL

OFFSHORE WEST AFRICA

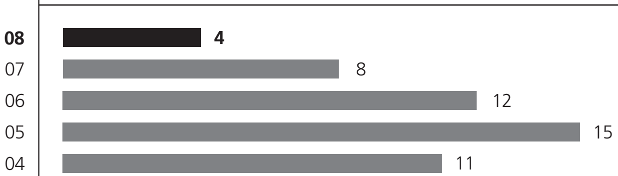
We maintain a high working interest for all of our Offshore West Africa assets and have 100% operatorship of our assets. This is an area that once again delivers high-value, light crude oil, providing development opportunities with significant exploration upside. We capitalize on strong government relationships and leverage the technical/operational expertise from the North Sea.

At Baobab in Offshore Côte d'Ivoire, the second phase of our program is on track. We are increasing production following well failures that occurred in 2006, with three wells already re-drilled and a fourth well underway. Baobab remains a challenging field and we are proceeding cautiously. We have implemented a robust gravel pack technology in the replacement wells and through a measured approach, we anticipate a larger third phase program in the near future. At Espoir, also in Offshore Côte d'Ivoire, we have been upgrading our FPSO, leading to greater production from the field. This upgrade is targeted to be complete in 2009.

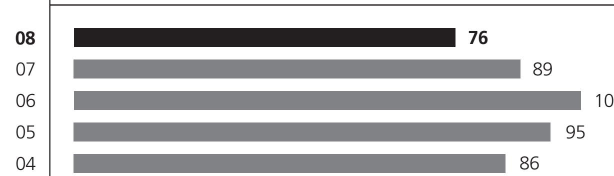
At Olowi in Offshore Gabon, development drilling has begun and first crude oil is targeted for early 2009. Additional wells will be drilled throughout the year with a production plateau of 20,000 bbl/d targeted to be reached and maintained in 2010.

Long-term plans for Offshore West Africa include a cautious and cost conscious approach towards the development of Baobab. At Espoir, we will continue with infill programs, optimizing our facilities. At Olowi, we will sustain production with continued platform drilling.

International successful crude oil wells drilled
(net wells)



International total production
(mboe/d)



horizon oil sands project

After roughly four years of planning, followed by four years of construction, the Horizon Project successfully and sustainably produced its first barrels of high quality, low-sulphur, 34° API, sweet synthetic crude oil in 2009. First production of SCO was a major milestone for Canadian Natural and we are very pleased with the success of the project. Acting as our own primary contractor on the Horizon Project, we have built a core competency in executing large scale projects from the ground up and have learned a great deal from the construction and start up of Phase 1.

The Horizon Project includes a surface oil sands mining and bitumen extraction plant, complimented by on-site bitumen upgrading with associated infrastructure to produce high quality SCO. Canadian Natural holds extensive leases that are estimated to contain approximately 16 billion barrels of oil in place and six to eight billion barrels of mineable reserves and contingent resources. The Horizon Project is located on these leases just north of Fort McMurray, Alberta in the Athabasca region. Due to the massive resource base, the mine and plant facilities are expected to produce for decades without production declines normally associated with conventional crude oil production.

The total construction costs for Phase 1 were approximately $9.7 billion, or $88,182 per flowing barrel of capacity. The final cost was 43% above our original estimate of $6.8 billion first set in 2004. However, the total cost of the Horizon Project comes in well below the industry average for current and future projects with similar facilities. First synthetic crude oil was achieved approximately five months beyond the initial target we set upon project sanctioning in 2005. Although both the cost and schedule were over initial targets, the project was built in an extremely volatile and inflationary business environment and in that respect, we consider it a success.

Operations have gone well since we started producing at the Horizon Project, with no major causes for concern. In a start up year without the benefit of targeted full production capacity, the operating cost for 2009 is forecast to be $35 to $40 per barrel of SCO. At full production, we target the operating cost for the life of the mine, at 250,000 bbl/d to be between $25 and $35 per barrel of SCO, a low-cost producer within the oil sands industry.

Full production capacity for Phase 1 is targeted to deliver 110,000 bbl/d of fully upgraded, light, sweet, SCO. We are targeting to reach full production capacity by late 2009. The early stages of production were approximately 55,000 bbl/d. Full ramp up to 110,000 bbl/d is targeted to be reached in 2009 as we continue to fine tune the plant to design rates with a focus on safety and reliability.

Looking to the future of the Horizon Project, Phase 1 is just the first step in value creation from this significant asset. A considerable amount of capital for infrastructure was included in Phase 1 in anticipation of future phases. These include but are not limited to, support infrastructure such as the aerodrome, buildings, shops, warehouses, camps and roads, site preparation, the piperack, coker foundations, gas and power distributions, the majority of underground piping and so on. There is also the added benefit that a large portion of this work was completed early on in the construction process, a much less inflationary business environment. Canadian Natural is in the position to leverage the benefits from our existing operation into future expansions.

Réal J. H. Doucet
SENIOR VICE-PRESIDENT,
OIL SANDS

The expansions to the Horizon Project have been broken into four tranches. Going forward, Canadian Natural wants to avoid the "mega-project" approach to development and feel that breaking the overall expansion into smaller, more manageable pieces will lead to enhanced project and cost control. Tranche 1 of the expansion was completed during 2007. This tranche included engineering and design specifications for greater production capacity, the setting of additional coker foundations, other supporting infrastructure, and the procurement of long lead equipment such as coke drums, reactors and mobile equipment. Future tranches of the expansion are currently being re-profiled, taking project control to the next level. We will see incremental production gains throughout the completion of future tranches, with targeted full facility capacity between 232,000 and 250,000 bbl/d. Further phases of expansion (Phases 4 and 5) will bring the ultimate capacity to 500,000 bbl/d.

TARGETED ACTIVITIES WITHIN FUTURE EXPANSIONS (PHASE 2/3)

Tranche 1 (completed)

Planned basis for future expansions by:

- Creating engineering design specification (232,000 bbl/d to 250,000 bbl/d SCO);
- Completing front end engineering and design;
- Building coker foundations and some supporting infrastructure; and
- Ordering and transporting to site long lead equipment (coke drums, reactors, mobile equipment).

Tranche 2

Facilitates potential production gains by 5% to 15% by:

- Increasing uptime and reliability (Ore Preparation Plant ("OPP") – train 3 and Hydrotransport);
- Ensuring environmental commitments are met (Gas Recovery Unit, Sulphur Plant – train 3);
- Increasing reliability ("Flood the Upgrader" and mine equipment); and
- Planning the debottlenecking process.

Tranche 3

Increases production by 10,000 to 20,000 bbl/d SCO by:

- Reducing energy and operating costs (new tailings technology);
- Expanding mining capability (mining equipment and shops);
- Increasing plant capacity (coker expansion); and
- Adding environmental efficiencies (CO_2 recovery).

Tranche 4

Expands to full capacity of 232,000 to 250,000 bbl/d SCO through:

- OPP (trains 4 and 5);
- Extraction (retrofit trains 1 and 2);
- Froth Treatment Plant (train 2);
- Vacuum Recovery Unit and Diluent Recovery Unit;
- Hydrotreating (2 units);
- Hydrogen Plant;
- Sulphur Plant (train 4);
- Cogeneration and Heat Integration; and
- Tankage.

The timing of construction for future expansions is critical for cost control and we position the Company to take advantage of the recent downturn in market activity. However, we are not driven to increase production at the expense of economic returns. The barrels are in the ground and will still be there when we are ready to proceed with our expansions; when the economics are right. Future phases will go ahead, it is just a matter of when and how. The Horizon Project asset is substantial and anticipated to provide significant free cash flow well into the future. The development of this world-class asset is predicated upon generating the greatest value for our shareholders.

marketing

The 2008 business environment was defined by commodity price volatility throughout the course of the year. 2008 will be recognized for the financial uncertainty caused by high prices midway through the year followed by the financial crisis and the beginning of a significant recession. In spite of this changing business environment, Canadian Natural's business approach remains focused and disciplined and this applies without exception to our marketing strategies and activities.

NATURAL GAS

Canadian Natural's long-term natural gas marketing objective is to maximize the realized price for our overall portfolio. Canadian Natural's realized wellhead price in 2008 was $8.39/mcf, 22% higher than in 2007. The AECO and NYMEX index both rose respectively by 23% and 29%. The average Canadian dollar strengthened slightly relative to the US dollar by 1% in 2008. Mild weather throughout 2008 and lower industrial demand late in the year caused natural gas prices to decline and resulted in full storage capacity by the third week of November. In the US, prolific increase from shale gas production and a 6% increase in wells completed, increased supply by 8.6% to 57.6 bcf/d. Domestically, overall Canadian natural gas production dropped by approximately 3% to 16.2 bcf/d over the year as completions were down 2% from the previous year.

The annual volume of Liquid Natural Gas ("LNG") imported into the US was lower than the previous year at 0.94 bcf/d as price differentials were biased in favor of the European and Asian markets. The current forward strips for worldwide natural gas markets suggest a continued low volume of LNG imports for 2009. The commissioning of several new liquefaction facilities announced for the next two years may change the pricing dynamics in favor of those markets with the capacity to receive and store these incremental volumes.

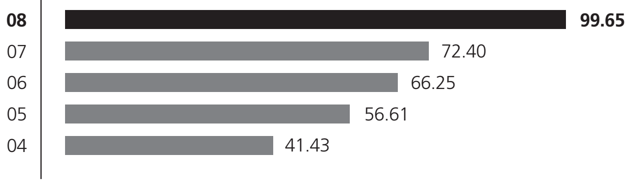
CRUDE OIL

Crude oil prices were extremely volatile in 2008 with the NYMEX West Texas Intermediate ("WTI") averaging US$99.65/bbl, exceeding the previous year by 38%. The pricing reached its peak on July 11 at US$147.27/bbl prior to beginning its downward spiral. This decline was caused by the loss of demand due to the worldwide financial crisis and bottomed at a low of US$32.40/bbl on December 19. The international benchmark Dated Brent was 34% higher than in 2007 at US$96.99/bbl.

Canadian Natural's realized wellhead price in 2008 was $82.41/bbl, 49% higher than 2007. The price differential for Canadian heavy crude oil, as measured by the Western Canadian Select crude oil blend ("WCS") price at Hardisty, Alberta improved by 12% over 2007 to a narrow differential of 20% of the NYMEX WTI for the yearly average in 2008. WCS heavy crude oil differentials narrowed to an attractive 13% of WTI in July and August in response to strong worldwide demand for diesel fuels and low gasoline cracking spreads. The continued declines in the volumes from Mexico and Venezuela also contributed to stronger demand for Canadian heavy crude oil barrels and resulted in excellent realized prices for this important component of our portfolio.

Our goal is to maximize the value of our crude oil portfolio in whatever market condition we are faced with. Canadian Natural's strategy consists of three main components: the blending of various crude oil streams and diluents to better serve the needs of our refining customers, the supportive participation in the expansion of pipeline export capacity and finally, the support and potential participation in projects adding incremental conversion capacity for bitumen and SCO.

WTI crude oil reference pricing
(US$/bbl)



NYMEX natural gas reference pricing
(US$/mmbtu)

Réal M. Cusson
SENIOR VICE-PRESIDENT, MARKETING

The WCS crude oil stream is a blend of several conventional crude oils, bitumen and diluents from either conventional or synthetic sources. WCS is used as the benchmark for Canadian heavy crude oil marketed out of the WCSB. Canadian Natural contributes, on average, approximately 150,000 bbl/d to the WCS blend, which is 55% of the total stream. The blending of WCS allows the Company to reduce its blending, logistics and storage thereby increasing the heavy crude oil netback for a significant portion of our heavy crude oil production.

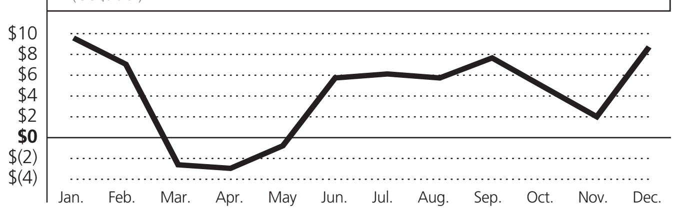
The second component of our crude oil marketing strategy includes the expansion of pipeline systems to open up new markets for heavy crude oil and SCO. Canadian Natural has supported industry export initiatives such as the Spearhead Pipeline to Cushing, Oklahoma, Southern Access to the upper PADD II market and Kinder Morgan's west coast expansion.

Canadian Natural is also a key supporter of the Keystone crude oil pipeline system that will provide access to the US Gulf Coast ("USGC") markets by 2012. The first phase of this project is currently under construction and is targeted to be in service in the first quarter of 2010 and reach Cushing, Oklahoma one year later. The second phase, Keystone XL, will provide an average of 910,000 bbl/d but requires regulatory approvals. The target completion period is the first quarter of 2012 with potential additions of laterals to USGC terminals by 2013. Canadian Natural has committed 120,000 bbl/d for an initial term of 20 years for firm service on Keystone XL to the USGC.

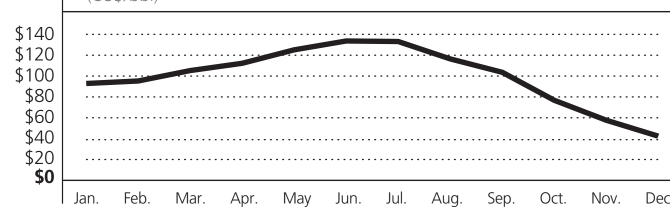
The third component of our long-term marketing strategy is supported by our commitment to supply 100,000 bbl/d for an initial term of 20 years to a large USGC refiner. This anchors an expansion project adding more coking capacity to this refiner's already complex configuration. The uncommitted Canadian Natural volumes available in the USGC are targeted for the general refining spot and term markets of 45,000 bbl/d. All of our sales in the USGC area will receive the prevailing market price.

These agreements represent a step forward in the implementation of our defined marketing plan to improve the margins we realize on our heavy crude oil production and to reduce the volatility historically experienced in the heavy crude oil markets. This strategic marketing component is part of the Company's long-term plan to develop its heavy oil production capacity.

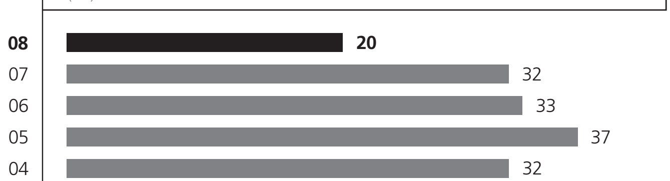
2008 Mayan - WCS realized price spread
(US$/bbl)



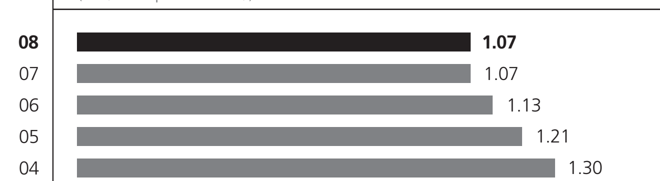
2008 WTI crude oil reference pricing
(US$/bbl)



WCS price differential to WTI
(%)



Canada/US average exchange rate
(US$ in equivalent C$)



PRICE RISK MANAGEMENT

Canadian Natural utilizes hedging techniques to provide some assurance on price realizations and to protect cash flow generation capability in order to fund ongoing development programs. Generally, the downside pricing risks associated with various commodities are determined and, if deemed appropriate, financial derivatives are used to limit risk. Currency exposures are also monitored and may be hedged along with the commodities. Starting in January 2009, our hedge policy will allow 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 further information on the particulars of this hedge program please refer to the Management's Discussion and Analysis and the Consolidated Financial Statements.

MIDSTREAM

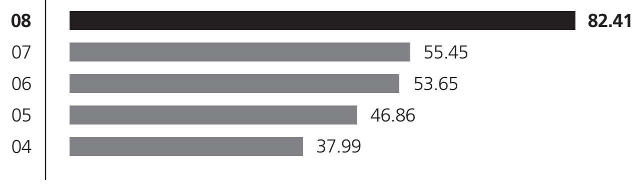
Our midstream assets consist of the 100% owned and operated ECHO Pipeline, a 15% interest in the Cold Lake Pipeline system, a 62% interest in the Company-operated Pelican Lake Pipeline, and a 50% interest in the 84 megawatt co-generation unit located at the Primrose facility. The midstream assets allow us to control and optimize transportation costs for about 85% of our heavy crude oil production. It also generates additional revenue from third party volumes, along with the sale of surplus electricity. ECHO Pipeline operated at 92% utilization in 2008 and is the only pipeline delivering undiluted raw bitumen to Hardisty terminals. Crude volumes delivered from ECHO pipeline play an important role in our heavy crude oil blending and marketing strategy for WCS and other diluted bitumen blends.

In 2008, the Company committed firm capacity of 42,000 bbl/d for an initial term of 10 years to anchor a new pipeline from our Nipisi terminal to Edmonton. This project, to be built by the Pembina Pipeline Income Fund ("Pembina"), still needs to obtain full regulatory approvals and is targeted for completion in July 2011. This new pipeline project includes a diluent supply pipeline to Nipisi for the blending of our increasing production volumes from our Pelican Lake area.

The new pipeline, owned and operated by Pembina, built to ship SCO from our Horizon Project to refineries in Edmonton has been fully operational since November 1, 2008.

We are currently reviewing a detailed forecast for Cold Lake production from the Primrose area to determine the timing and size of incremental pipeline capacity required to support our expansion plans for 2010 and beyond.

Company average crude oil and NGLs selling price
(C$/bbl)



Company average natural gas selling price
(C$/mcf)

health and safety, environment and community

For Canadian Natural, "doing it right with fun and integrity" is a commitment we make towards responsible operations and environmental stewardship. Our management systems encourage continuous corporate improvement in the areas of health and safety, infrastructure integrity, environmental management and community support for our employees, contractors and stakeholders. We recognize that improvement in these areas is fundamental to our long-term growth.

HEALTH AND SAFETY

Canadian Natural conducts operations in a way that protects the health and safety of employees, contractors, the public and the environment. We continue to enhance safety awareness by maintaining a focus on safety programs and processes. In 2008 our health and safety performance benchmarks surpassed internal targets and continue to improve. Over the past six years, the total recordable injury frequency has decreased across all our operations.

Canadian Natural has a very aggressive audit program with over 500 audit inspections conducted in 2008. All internal audits are performed using a Company-developed safety and compliance audit protocol. Our ongoing initiatives ensure that Canadian Natural maintains an Energy Resources Conservation Board satisfactory inspection rate that is significantly better than the industry average.

In 2008, the Horizon Project underwent the last stage of construction and transitioned into commissioning and start-up of operations. Despite the busy year, the Horizon Project achieved 24 million hours Lost Time Injury Free. The Horizon Project Health and Safety Group worked closely with all the groups involved and implemented safety prequalification programs for all contractors to ensure smooth transitions and safe commissioning and start-up.

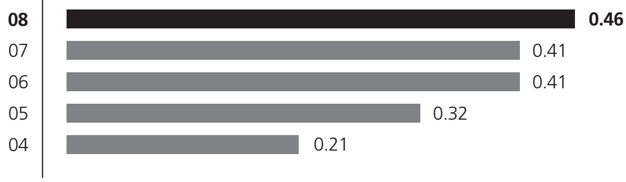
We are also working hard to continue to improve worksite safety behaviours by delivering targeted safety leadership training. In 2008 we implemented an "Operations Readiness" Program which included Oil Sands Safety Association ("OSSA") approved Safe Work Permit training. We also successfully embedded new electronic Integrated Safe System of Work ("ISSoW") on all our North Sea installations.

INFRASTRUCTURE INTEGRITY

Canadian Natural is committed to managing the integrity of its pipelines and facilities. We've established Asset Integrity Programs at our operations which develop and implement the pressure equipment guidelines to meet corporate standards and regulatory requirements. The Integrity Group tracks and coordinates inspections for over 36,000 pieces of pressure equipment. All critical findings from proactive inspections are resolved via repair or replacement. The Integrity Group also tracks the resolution of findings from proactive inspections that are not an immediate risk but may pose a problem down the road.

We work diligently to maintain the structural integrity of all our operations, especially our more mature installations and pipelines. We take a proactive approach to Risk Based Inspection ("RBI"). RBI is used to ensure that inspections are carried out at an appropriate frequency. It also helps us ensure that inspections address potential failure modes for the system. This approach allows us to optimize inspection intervals and in many cases we're able to extend intervals based upon this analysis. In every project, we strive to ensure that all assets operate safely and effectively for the life of field of all the assets within Canadian Natural's portfolio.

CO_2e reductions from gas conservation
Primrose and Wolf Lake thermal operations (megatonnes)



In the past five years, our investment in solution gas conservation has prevented 8.2 million tonnes of CO_2e emissions.

Lyle G. Stevens
SENIOR VICE-PRESIDENT, EXPLOITATION

ENVIRONMENT

Environmental stewardship is an essential element of all Canadian Natural's operations. Management and operating personnel are committed to ensuring that planning, training and due diligence are key elements in our environmental management programs. Environmental strategies target corporate standards, operations compliance, liability reduction, air emission management, reduction of fresh water use and minimizing our landscape footprint.

Canadian Natural's Environmental Management System ("EMS") focuses on ensuring our field operations meet all corporate standards and regulatory requirements and minimizes their environmental impact. In 2008, we continued the development, enhancement and implementation of the EMS in our conventional operations and the Horizon Project. In our North Sea operations, two more installations achieved ISO 14001 certification; all Canadian Natural's North Sea operations are now certified. In 2008, emergency preparedness and response plans were reviewed and enhanced in our West Africa operations.

Canadian Natural Environment staff continued implementing our rigorous audit program, which includes a formal review of environmental compliance and risk management activities for a site. In addition, many third-party audits were conducted at Canadian Natural facilities and key well sites throughout the year. Action items resulting from these audits are tracked to ensure appropriate corrective and preventive actions are taken in a timely manner.

For North American conventional operations, our liability reduction programs focus on abandonment, reclamation and decommissioning activities. In 2008, we abandoned 116 wells and 373 pipelines, and received 329 reclamation certificates.

At our Horizon Project, reclamation work has already begun, prior to full operation of the facility. In 2008, we reclaimed 80 hectares of land.

Our industry faces regulatory and stakeholder concerns associated with air emissions from operations, specifically greenhouse gases ("GHGs") and air pollutants. Canadian Natural is committed to developing innovative and effective solutions to manage GHG emissions and air quality issues. Implementation of flaring and venting reductions and fuel and solution gas conservation programs continue.

Year-over-year flaring volumes decreased by 17% due to improved operational practice and due to lower natural gas production volumes. In 2008, Canadian Natural spent $6.3 million and completed 101 solution gas conservation projects which reduced over 0.84 million tonnes of CO_2e. The focus of the majority of these projects was to increase the efficiency of our operations and conserve natural gas.

In Alberta, Canadian Natural's solution gas conservation rate was 85%. This has improved significantly from a rate of 63% in 2000.

The Horizon Project will incorporate numerous advancements in technology to reduce GHG emissions including continued research, development and implementation of a process to sequester CO_2 into tailings. At the completion of Phases 2/3 of the Horizon Project, we believe this process will sequester approximately 219,000 tonnes of CO_2 annually. Our *"Taking Action on Greenhouse Gas Emissions"* document outlines our strategy to address GHG emissions from our operations in the short and long term and is available on our web site.

Carbon Capture and Storage ("CCS") has emerged as the centerpiece of Alberta's GHG reduction efforts in the medium to long term. Canadian Natural is currently operating a CO_2 Enhanced Oil Recovery ("EOR") project in Southern Alberta. We will be working with the Alberta government in 2009 on opportunities and incentives to further develop CCS within our operations.

In our international operations, we continue to pursue emission reduction opportunities including improvements to flare systems and natural gas turbines.

Throughout our operations, we consistently strive to reduce our fresh water use. Our ongoing work to meet this goal includes recycling a high percentage of produced water, increasing the use of brackish/saline water and using produced water in our drilling and abandonment operations. Increased brackish/saline water use at our Primrose and Wolf Lake operations continues to enable increased bitumen production without an equivalent increase in fresh water use. In 2008, the relative proportion of fresh water to brackish water use continued to decrease at the Primrose and Wolf Lake operations. Two additional brackish wells were installed in 2008 increasing brackish production and treatment capacity. This increased supply is helping to meet the needs of the Primrose East Expansion Project.

In 2008, construction of the Wapan Sakahikan lake was completed at the Horizon Project site and was filled with water. This lake provides new fish habitat as compensation for habitat lost due to project development. Water quality monitoring at the lake is ongoing to determine the timing for stocking the lake with fish and will continue to ensure appropriate water quality to sustain fish populations.

Water management at the Horizon Project continues to be a priority for Canadian Natural. Our water withdrawal from the Athabasca River began in 2007, and we continue to withdraw amounts far below our approval limits. In 2008, we continued to work with other oil sands operators in the Athabasca Region to ensure that water use is coordinated and does not exceed regulatory limits.

COMMUNITIES AND STAKEHOLDERS

Canadian Natural is committed to operating in a socially responsible way and maintaining a long-term presence in the communities where we operate. Our business activities contribute to the quality of life and economic health in communities where we do business. In 2008, Canadian Natural continued its wide range of community investment programs.

Our community investment projects benefit people living in communities across Western Canada, the UK and West Africa by providing financial and volunteer support for the projects that meet their vision for the future. Overall, Canadian Natural's community sponsorship and funding support in 2008 totaled more than $4 million.

We strongly believe that education and training are fundamental to developing people. Throughout our operations, Canadian Natural supports a number of initiatives in building labour capacity in communities to meet the long-term human resource needs in the crude oil and natural gas industry. In 2008 we supported programs such as the Petroleum Employment Training Program, the Northeast British Columbia's Stay-in-School Program and Inside Education.

Through the Canadian Natural Building Futures scholarship program we are proud to support students who are pursuing education and training related to crude oil and natural gas. In 2008 we awarded approximately $100,000 in scholarships to 76 students living in all regions of Alberta, British Columbia and Saskatchewan, including many Aboriginal students living near our operations.

In 2008, we continued to develop and sustain strong working relationships with our stakeholders. We aim to understand their interests so we can consider and incorporate their input in our operations. Where possible, we strive to integrate economic, environmental and social considerations in the decision-making process across all of our business activities.

Canadian Natural works closely with the more than 55 Aboriginal communities near our operations in Western Canada to strengthen mutual understanding and co-operation and enhance the opportunities for economic participation in our crude oil and natural gas developments.

2008 review

year-end reserves
independent evaluation

DETERMINATION OF RESERVES

For the year ended December 31, 2008, Canadian Natural retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, and proved and probable crude oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from certain of the 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 United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). Canadian Natural discloses its reserve reconciliation net of royalties in adherence to SEC requirements.

The Company has disclosed proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information.

The SEC requires that oil sands mining reserves be disclosed separately from conventional oil and gas disclosure. Canadian Natural retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate Phase 1 to Phase 3 of the Company's Horizon Project under SEC Industry Guide 7 requirements.

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.

Conventional crude oil, NGLs and natural gas include all of the Company's light and medium, heavy, and thermal crude oil, natural gas, coal bed methane and natural gas liquid activities. They do not include the Company's oil sands mining assets.

CORPORATE CONVENTIONAL NET RESERVES

Crude oil, natural gas and NGLs proved reserves decreased by 0.5% replacing 95% of production. This was accomplished at all-in finding and on-stream cost of $20.68 per barrel of oil equivalent for proved reserves and $14.66 per barrel of oil equivalent for proved and probable reserves.

In the Evaluation Reports, 53% of crude oil and NGLs proved reserves were assigned to the proved undeveloped category, compared to 46% in 2007.

In the Evaluation Reports, 23% of natural gas proved reserves were assigned to the proved undeveloped category reflecting the generally shorter lead times required for natural gas developments in Canada.

In the Evaluation Reports, total proved and probable reserves increased by 2%.

NORTH AMERICA CONVENTIONAL NET RESERVES

Crude oil and NGLs proved reserves increased by 3% replacing 137% of production. Natural gas proved reserves increased by 0.1% replacing 100% of 2008 production.

INTERNATIONAL CONVENTIONAL NET RESERVES

North Sea proved reserves decreased by 56 million barrels to 267 million barrels of oil equivalent, which represents 14% of the total proved Company reserves. The decrease was primarily due to changes in year over year pricing.

In Offshore West Africa proved reserves increased to 158 million barrels in 2008 from 139 million barrels in 2007.

HORIZON OIL SANDS MINING NET RESERVES

The net proved synthetic crude oil reserves increased to 1.95 billion barrels. The net proved and probable synthetic crude oil reserves were 2.94 billion barrels.

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES (1)

	December 31, 2008			
	Proved Developed(2)	**Proved Undeveloped(2)**	**Proved Total(2)**	**Proved and Probable(3)**
Crude oil and NGLs (mmbbl)				
North America	**428**	**520**	**948**	**1,599**
North Sea	**97**	**159**	**256**	**399**
Offshore West Africa	**107**	**35**	**142**	**191**
	632	**714**	**1,346**	**2,189**
Natural gas (bcf)				
North America	**2,690**	**833**	**3,523**	**4,619**
North Sea	**45**	**22**	**67**	**94**
Offshore West Africa	**89**	**5**	**94**	**131**
	2,824	**860**	**3,684**	**4,844**
Total reserves (mmboe)	**1,103**	**857**	**1,960**	**2,996**
Reserve replacement ratio(4) (%)			**95%**	**134%**
Cost to develop(5) ($/boe)				
10% discount	**$ 0.80**	**$ 6.94**	**$ 3.48**	**$ 3.03**
15% discount	**$ 0.70**	**$ 6.04**	**$ 3.03**	**$ 2.60**
Present value of conventional reserves(6) ($ millions)				
10% discount	**$ 12,987**	**$ 2,200**	**$ 15,187**	**$ 19,264**
15% discount	**$ 11,253**	**$ 1,164**	**$ 12,417**	**$ 15,179**

	December 31, 2007			
	Proved Developed(2)	Proved Undeveloped(2)	Proved Total(2)	Proved and Probable(3)
Crude oil and NGLs (mmbbl)				
North America	426	494	920	1,545
North Sea	240	70	310	405
Offshore West Africa	70	58	128	186
	736	622	1,358	2,136
Natural gas (bcf)				
North America	2,731	790	3,521	4,602
North Sea	58	23	81	113
Offshore West Africa	53	11	64	88
	2,842	824	3,666	4,803
Total reserves (mmboe)	1,210	759	1,969	2,937
Reserve replacement ratio(4) (%)			110%	87%
Cost to develop(5) ($/boe)				
10% discount	$ 1.25	$ 6.73	$ 3.36	$ 3.20
15% discount	$ 1.09	$ 6.43	$ 3.15	$ 2.99
Present value of conventional reserves(6) ($ millions)				
10% discount	$ 25,767	$ 8,810	$ 34,577	$ 44,286
15% discount	$ 21,924	$ 6,082	$ 28,006	$ 34,604

OIL SANDS MINING RESERVES(1)

The following table sets out Canadian Natural's reserves of synthetic crude oil from the Horizon Project Oil Sands leases.

	December 31, 2008		December 31, 2007	
	Proved Total	**Proved and Probable**	Proved Total	Proved and Probable
Net reserves, after royalties (mmbbl)				
Synthetic crude oil(7)	**1,946**	**2,944**	1,761	2,680

CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES(1)(8)

	North America	North Sea	Offshore West Africa	Total
Proved reserves (mmbbl)				
Reserves, December 31, 2006	887	299	130	1,316
Extensions and discoveries	30	–	–	30
Infill drilling	10	6	–	16
Improved recovery	3	–	–	3
Property purchases	1	–	–	1
Property disposals	–	(3)	–	(3)
Production	(77)	(20)	(10)	(107)
Revisions of prior estimates	66	28	8	102
Reserves, December 31, 2007	920	310	128	1,358
Extensions and discoveries	**51**	**–**	**–**	**51**
Infill drilling	**7**	**6**	**4**	**17**
Improved recovery	**10**	**–**	**–**	**10**
Property purchases	**–**	**–**	**–**	**–**
Property disposals	**–**	**–**	**–**	**–**
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	**948**	**256**	**142**	**1,346**
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2006	1,502	422	195	2,119
Extensions and discoveries	41	–	–	41
Infill drilling	52	6	–	58
Improved recovery	4	–	–	4
Property purchases	2	6	–	8
Property disposals	–	(3)	–	(3)
Production	(77)	(20)	(10)	(107)
Revisions of prior estimates	21	(6)	1	16
Reserves, December 31, 2007	1,545	405	186	2,136
Extensions and discoveries	**76**	**–**	**–**	**76**
Infill drilling	**9**	**4**	**–**	**13**
Improved recovery	**23**	**–**	**–**	**23**
Property purchases	**6**	**–**	**–**	**6**
Property disposals	**–**	**–**	**–**	**–**
Production	**(76)**	**(17)**	**(8)**	**(101)**
Economic revisions due to prices	**59**	**(45)**	**8**	**22**
Revisions of prior estimates	**(43)**	**52**	**5**	**14**
Reserves, December 31, 2008	**1,599**	**399**	**191**	**2,189**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES[(1)(8)]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2006	3,705	37	56	3,798
Extensions and discoveries	134	–	–	134
Infill drilling	124	3	–	127
Improved recovery	8	–	–	8
Property purchases	12	–	–	12
Property disposals	–	–	–	–
Production	(503)	(5)	(4)	(512)
Revisions of prior estimates	41	46	12	99
Reserves, December 31, 2007	3,521	81	64	3,666
Extensions and discoveries	**140**	**–**	**–**	**140**
Infill drilling	**46**	**(1)**	**6**	**51**
Improved recovery	**6**	**–**	**–**	**6**
Property purchases	**77**	**–**	**–**	**77**
Property disposals	**(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**
Proved and probable reserves (bcf)				
Reserves, December 31, 2006	4,857	93	99	5,049
Extensions and discoveries	177	–	–	177
Infill drilling	163	3	–	166
Improved recovery	8	–	–	8
Property purchases	17	1	–	18
Property disposals	(1)	–	–	(1)
Production	(503)	(5)	(4)	(512)
Revisions of prior estimates	(116)	21	(7)	(102)
Reserves, December 31, 2007	4,602	113	88	4,803
Extensions and discoveries	**182**	**–**	**–**	**182**
Infill drilling	**58**	**(3)**	**–**	**55**
Improved recovery	**8**	**–**	**–**	**8**
Property purchases	**93**	**–**	**–**	**93**
Property disposals	**(6)**	**–**	**–**	**(6)**
Production	**(449)**	**(4)**	**(4)**	**(457)**
Economic revisions due to prices	**(27)**	**(63)**	**8**	**(82)**
Revisions of prior estimates	**158**	**51**	**39**	**248**
Reserves, December 31, 2008	**4,619**	**94**	**131**	**4,844**

CONVENTIONAL FINDING AND ON-STREAM COSTS

	2008	2007	2006	Three Year Total
Net reserve replacement expenditures ($ millions)	**$ 3,475**	$ 3,027	$ 8,727	**$ 15,229**
Net reserve additions (mmboe) [9]				
Proved	**168**	212	540	**920**
Proved and probable	**237**	168	865	**1,270**
Finding and on-stream costs ($/boe) [10]				
Proved	**$ 20.68**	$ 14.28	$ 16.16	**$ 16.55**
Proved and probable	**$ 14.66**	$ 18.02	$ 10.09	**$ 11.99**

RESERVES CLASSIFICATION BY PRODUCT, NET OF ROYALTIES[1]

	December 31, 2008			
	Proved Developed[2]	**Proved Undeveloped**[2]	**Proved Total**[2]	**Proved and Probable**[3]
Light crude oil and NGLs				
North America	**5%**	**1%**	**6%**	**5%**
North Sea	**5%**	**8%**	**13%**	**13%**
Offshore West Africa	**5%**	**2%**	**7%**	**6%**
Total	**15%**	**11%**	**26%**	**24%**
Heavy crude oil and NGLs				
North America – Primary Heavy	**4%**	**1%**	**5%**	**4%**
North America – Pelican Lake	**4%**	**3%**	**7%**	**7%**
North America – Thermal	**9%**	**21%**	**30%**	**37%**
Total	**17%**	**25%**	**42%**	**48%**
Total crude oil and NGLs				
North America	**22%**	**26%**	**48%**	**53%**
North Sea	**5%**	**8%**	**13%**	**13%**
Offshore West Africa	**5%**	**2%**	**7%**	**6%**
Total	**32%**	**36%**	**68%**	**72%**
Natural gas				
North America	**23%**	**7%**	**30%**	**26%**
North Sea	**1%**	**–**	**1%**	**1%**
Offshore West Africa	**1%**	**–**	**1%**	**1%**
Total	**25%**	**7%**	**32%**	**28%**
Total Boe	**57%**	**43%**	**100%**	**100%**

(1) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below as well as constant year-end costs.

Crude oil and NGLs	Company Average Price (C$/bbl)	WTI @ Cushing Oklahoma (US$/bbl)	Hardisty Heavy 12° API (C$/bbl)	North Sea Brent (US$/bbl)
2008	**$ 34.51**	**$ 44.60**	**$ 26.11**	**$ 41.76**
2007	$ 62.87	$ 96.00	$ 41.70	$ 96.02
2006	$ 51.11	$ 61.05	$ 41.94	$ 58.93

Natural gas	Company Average Price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	Alberta AECO C (C$/mmbtu)	British Columbia Huntingdon Sumas (C$/mmbtu)
2008	**$ 6.51**	**$ 5.63**	**$ 6.34**	**$ 7.48**
2007	$ 6.48	$ 6.80	$ 6.52	$ 6.96
2006	$ 6.07	$ 5.52	$ 6.13	$ 6.52

A foreign exchange rate of US$0.82/C$1.00 was used in the 2008 evaluation; US$1.01/C$1.00 was used in the 2007 evaluation; US$0.86/C$1.00 was used in the 2006 evaluation.

(2) Proved reserve estimates and values were evaluated in accordance with the SEC requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the COGEH and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total discounted future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Future development costs and associated material well abandonment costs have been applied against future net revenues.

(7) Synthetic crude oil reserves are based on upgrading of the bitumen using technologies implemented at the Horizon Project.

(8) In 2007, revisions of prior estimates includes economic revisions due to prices.

(9) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

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

management's discussion and analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements 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 existing and future developments, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby 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 Canadian Natural Resources Limited (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, uncertainties and other factors 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 factors 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 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 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, 2008. 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 18 to the consolidated financial statements. All dollar amounts are referenced in 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 are the Company's interest before royalties, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. The following discussion and analysis refers primarily to the Company's 2008 financial results compared to 2007 and 2006, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2009.

Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2008 and its Annual Information Form for the year ended December 31, 2008, is available on SEDAR at www.sedar.com.

This MD&A is dated March 4, 2009.

ABBREVIATIONS

ACC	Anadarko Canada Corporation
AECO	Alberta natural gas reference location
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
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
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 Project	Horizon Oil Sands Project
LIBOR	London Interbank Offered Rate
mcf	thousand cubic feet
mmbbl	million barrels
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SCO	Synthetic light crude oil
SEC	United States Securities and Exchange Commission
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
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, Pelican Lake crude oil (2), primary heavy crude oil and thermal heavy crude oil;
- 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 conventional 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 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, including the Horizon Project and its conventional crude oil and natural gas opportunities. 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, like the acquisition of ACC in 2006, 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, 2008 include the following:

- Achieved record levels of net earnings, adjusted net earnings from operations, and cash flow from operations;
- Achieved annual crude oil and natural gas production guidance;
- Completed the construction of and achieved first production from the Primrose East Expansion;
- Completed drilling and brought three wells back on production at the Baobab Field, Côte d'Ivoire;
- Development continued on the Olowi Field in offshore Gabon with first oil targeted for Spring 2009;
- Substantially completed construction of Phase 1 of the Horizon Project; and
- Increased dividends per common share.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)	2008	2007	2006
Revenue, before royalties	**$ 16,173**	$ 12,543	$ 11,643
Net earnings	**$ 4,985**	$ 2,608	$ 2,524
Per common share – basic and diluted	**$ 9.22**	$ 4.84	$ 4.70
Adjusted net earnings from operations (1)	**$ 3,492**	$ 2,406	$ 1,664
Per common share – basic and diluted	**$ 6.46**	$ 4.46	$ 3.10
Cash flow from operations (2)	**$ 6,969**	$ 6,198	$ 4,932
Per common share – basic and diluted	**$ 12.89**	$ 11.49	$ 9.18
Dividends declared per common share	**$ 0.40**	$ 0.34	$ 0.30
Total assets	**$ 42,650**	$ 36,114	$ 33,160
Total long-term liabilities	**$ 20,856**	$ 19,230	$ 19,399
Capital expenditures, net of dispositions	**$ 7,451**	$ 6,425	$ 12,025

(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)	2008	2007	2006
Net earnings as reported	$ 4,985	$ 2,608	$ 2,524
Stock-based compensation (recovery) expense, net of tax [(a)]	(38)	134	95
Unrealized risk management (gain) loss, net of tax [(b)]	(2,112)	977	(674)
Unrealized foreign exchange loss (gain), net of tax [(c)]	698	(449)	114
Effect of statutory tax rate and other legislative changes on future income tax liabilities [(d)]	(41)	(864)	(395)
Adjusted net earnings from operations	$ 3,492	$ 2,406	$ 1,664

(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 as part of the Horizon Project during the construction period.

(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 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. Income tax rate changes during 2006 resulted in an increase of future income tax liabilities of approximately $110 million in the North Sea, a reduction of approximately $438 million in North America, and a reduction of approximately $67 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	2008	2007	2006
Net earnings	$ 4,985	$ 2,608	$ 2,524
Non-cash items:			
Depletion, depreciation and amortization	2,683	2,863	2,391
Asset retirement obligation accretion	71	70	68
Stock-based compensation (recovery) expense	(52)	193	139
Unrealized risk management (gain) loss	(3,090)	1,400	(1,013)
Unrealized foreign exchange loss (gain)	832	(524)	134
Deferred petroleum revenue tax (recovery) expense	(67)	44	37
Future income tax expense (recovery)	1,607	(456)	652
Cash flow from operations	$ 6,969	$ 6,198	$ 4,932

For 2008, the Company reported net earnings of $4,985 million compared to net earnings of $2,608 million for 2007 (2006 – $2,524 million). Net earnings for the year ended December 31, 2008 included net unrealized after-tax income of $1,493 million related to the effects of risk management activities, changes in foreign exchange rates, stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2007 – $202 million; 2006 – $860 million). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2008 increased to $3,492 million from $2,406 million for 2007 (2006 – $1,664 million) primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and lower interest and administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

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, 2008 increased to $6,969 million ($12.89 per common share) from $6,198 million ($11.49 per common share) for 2007 (2006 – $4,932 million; $9.18 per common share). The increase was primarily due to the impact of higher realized pricing and lower interest and administration expense, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

For 2008, the Company's average sales price per bbl of crude oil and NGLs increased to $82.41 per bbl from $55.45 per bbl in 2007 (2006 – $53.65 per bbl). The Company's average natural gas price increased to $8.39 per mcf from $6.85 per mcf for 2007 (2006 – $6.72 per mcf).

Total production of crude oil and NGLs before royalties decreased to 315,667 bbl/d from 331,232 bbl/d for 2007 (2006 – 331,998 bbl/d). The decrease in crude oil and NGLs production was primarily due to lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds, the sale of the Company's working interest in the B-Block Fields late in 2007, and the impact of the shut in of a portion of the Baobab Field production, and in North America due to the cyclic nature of the Company's thermal production.

Total natural gas production before royalties decreased to 1,495 mmcf/d from 1,668 mmcf/d for 2007 (2006 – 1,492 mmcf/d). The decrease in natural gas production primarily reflected natural production declines due to 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 decreased to 564,845 boe/d from 609,206 boe/d for 2007 (2006 – 580,724 boe/d). Total production for 2008 was within the Company's previously issued guidance.

Operating highlights

		2008		2007		2006
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	**$**	**82.41**	$	55.45	$	53.65
Royalties		**10.48**		5.94		4.48
Production expense		**16.26**		13.34		12.29
Netback	**$**	**55.67**	$	36.17	$	36.88
Natural gas ($/mcf) (1)						
Sales price (2)	**$**	**8.39**	$	6.85	$	6.72
Royalties		**1.46**		1.11		1.29
Production expense		**1.02**		0.91		0.82
Netback	**$**	**5.91**	$	4.83	$	4.61
Barrels of oil equivalent ($/boe) (1)						
Sales price (2)	**$**	**68.62**	$	49.05	$	47.92
Royalties		**9.78**		6.26		5.89
Production expense		**11.79**		9.75		9.14
Netback	**$**	**47.05**	$	33.04	$	32.89

(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.

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)

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**
2007		Total		Dec 31		Sep 30		Jun 30		Mar 31
Revenue, before royalties	$	12,543	$	3,200	$	3,073	$	3,152	$	3,118
Net earnings	$	2,608	$	798	$	700	$	841	$	269
Net earnings per common share										
– basic and diluted	$	4.84	$	1.48	$	1.30	$	1.56	$	0.50

Net earnings (loss) over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, fluctuations in sales volumes, the impact of mark-to-market accounting of derivative financial instruments and stock-based compensation, fluctuations in depletion, depreciation and amortization charges and foreign exchange rates, and adjustments to future income tax liabilities due to statutory tax rate and other legislative changes. More specifically, volatility in quarterly net earnings was primarily due to:

- **Crude oil pricing**
  Crude oil prices reflected fluctuating demand, geopolitical uncertainties and fluctuations in the Heavy Differential in North America.

- **Natural gas pricing**
  Natural gas prices primarily reflected seasonal fluctuations in both the demand for natural gas and inventory storage levels, fluctuations in liquefied natural gas imports into the US, and increased shale gas production in the US.

- **Crude oil and NGLs sales volumes**
  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and development of the Espoir Field. Crude oil and NGLs sales volumes also reflected fluctuations in production from the North Sea and Offshore West Africa due to timing of liftings and maintenance activities and the impact of the shut in of a portion of the Baobab Field production.

- **Natural gas sales volumes**
  Natural gas sales volumes primarily reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America due to the allocation of capital to higher return crude oil projects, as well as natural decline rates.
- **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.
- **Risk management**
  Net earnings (loss) have fluctuated 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.
- **Changes in income tax expense**
  Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.
- **Stock-based compensation**
  Net earnings (loss) have fluctuated 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 over the eight most recently completed quarters.
- **Production expense**
  Production expense has fluctuated company wide primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters in all segments, fluctuations in product mix, and the impact of seasonal costs that are dependent on weather.
- **Depletion, depreciation and amortization**
  Depletion, depreciation and amortization expense has fluctuated due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, and estimated future costs to develop the Company's proved undeveloped reserves.

BUSINESS ENVIRONMENT

(Yearly average)	2008	2007	2006
WTI benchmark price (US$/bbl)	**$ 99.65**	$ 72.40	$ 66.25
Dated Brent benchmark price (US$/bbl)	**$ 96.99**	$ 72.59	$ 65.18
WCS blend differential from WTI (US$/bbl) (1)	**$ 20.03**	$ 23.25	$ 21.53
WCS blend differential from WTI (%) (1)	**20%**	32%	32%
Condensate benchmark price (US$/bbl)	**$ 100.10**	$ 72.88	$ 66.24
NYMEX benchmark price (US$/mmbtu)	**$ 8.95**	$ 6.92	$ 7.26
AECO benchmark price (C$/GJ)	**$ 7.71**	$ 6.26	$ 6.62
US / Canadian dollar average exchange rate	**$ 0.9381**	$ 0.9304	$ 0.8818
US / Canadian dollar year end exchange rate	**$ 0.8166**	$ 1.0120	$ 0.8581

(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 2008, with a high of approximately $1.03 in February 2008 and a low of approximately $0.77 in December 2008.

The overall increase in WTI pricing in 2008 reflected strong demand for crude oil and tight supply during the first half of 2008, followed by a significant decrease in demand as a result of worldwide financial and economic events during the fourth quarter of the year. WTI pricing was also impacted by ongoing geopolitical uncertainty resulting in increased market volatility. For 2008, WTI averaged US$99.65 per bbl, an increase of 38% compared to US$72.40 per bbl for 2007 (2006 – US$66.25 per bbl). WTI reached a high of US$147.27 per bbl on July 11, 2008 and a low of US$32.40 per bbl on December 19, 2008.

Brent averaged US$96.99 per bbl for 2008, an increase of 34% compared to US$72.59 per bbl for 2007 (2006 – US$65.18 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which was also impacted by worldwide financial and economic events late in the year.

The Company's realized crude oil prices benefited from strong commodity pricing during most of the year and a favorable Heavy Differential. The Heavy Differential averaged 20% of WTI for 2008, compared to 32% for 2007 (2006 – 32%). As the worldwide demand for diesel remained strong and the refinery cracking margins were relatively weak, the Heavy Differential continued to remain strong, despite the falling benchmark pricing late in 2008.

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 global economic slowdown resulting from worldwide financial and economic events. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$8.95 per mmbtu for 2008, an increase of 29% from US$6.92 per mmbtu for 2007 (2006 – US$7.26 per mmbtu). The Alberta based AECO natural gas pricing for 2008 increased 23% to average $7.71 per GJ from $6.26 per GJ in 2007 (2006 – $6.62 per GJ). During the first half of 2008, the demand and pricing for natural gas were tracking with oil pricing and general economic activity. During the second half of the year, natural gas pricing decreased due to a significant increase in production from shale gas reservoirs in the US and a significant decline in industrial demand caused by the onset of worldwide financial and economic events.

Operating, Royalty and Capital Costs

Strong commodity prices over the last several 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.

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial GHG emissions; however future Federal regulatory requirements remain uncertain. 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. Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012. 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.

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 its New Royalty Framework ("NRF") effective January 1, 2009. The NRF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the NRF, royalties payable vary according to commodity prices and the productivity of wells. Leading up to the January 2009 implementation of the NRF, the Alberta Government made several adjustments to the originally proposed formula to address unintended consequences. These adjustments affect royalties payable for certain natural gas and crude oil production wells. 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)	2006	Volumes	Prices	Other	2007	**Volumes**	**Prices**	**Other**	**2008**
North America									
Crude oil and NGLs	$ 5,262	$ 298	$ 287	$ –	$ 5,847	**$ (49)**	**$ 3,013**	**$ –**	**$ 8,811**
Natural Gas	3,804	452	46	–	4,302	**(531)**	**914**	**–**	**4,685**
	9,066	750	333	–	10,149	**(580)**	**3,927**	**–**	**13,496**
North Sea									
Crude oil and NGLs	1,600	(107)	82	–	1,575	**(334)**	**512**	**–**	**1,753**
Natural gas	16	(2)	8	–	22	**(5)**	**(1)**	**–**	**16**
	1,616	(109)	90	–	1,597	**(339)**	**511**	**–**	**1,769**
Offshore West Africa									
Crude oil and NGLs	931	(216)	36	–	751	**(136)**	**280**	**–**	**895**
Natural gas	19	5	1	–	25	**5**	**19**	**–**	**49**
	950	(211)	37	–	776	**(131)**	**299**	**–**	**944**
Subtotal									
Crude oil and NGLs	7,793	(25)	405	–	8,173	**(519)**	**3,805**	**–**	**11,459**
Natural gas	3,839	455	55	–	4,349	**(531)**	**932**	**–**	**4,750**
	11,632	430	460	–	12,522	**(1,050)**	**4,737**	**–**	**16,209**
Midstream	72	–	–	2	74	**–**	**–**	**3**	**77**
Intersegment eliminations and other (1)	(61)	–	–	8	(53)	**–**	**–**	**(60)**	**(113)**
Total	$ 11,643	$ 430	$ 460	$ 10	$ 12,543	**$ (1,050)**	**$ 4,737**	**$ (57)**	**$ 16,173**

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

Revenue increased 29% to $16,173 million for 2008 from $12,543 million for 2007 (2006 – $11,643 million). The increase was primarily due to increased realized crude oil and NGLs and natural gas prices company-wide.

For 2008, 17% of the Company's crude oil and natural gas revenue was generated outside of North America (2007 – 19%; 2006 – 22%). North Sea accounted for 11% of crude oil and natural gas revenue for 2008 (2007 – 13%; 2006 – 14%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2008 (2007 – 6%; 2006 – 8%).

ANALYSIS OF PRODUCT PRICES

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 77.42**	$ 49.16	$ 46.52
North Sea	**$ 100.31**	$ 74.99	$ 72.62
Offshore West Africa	**$ 97.96**	$ 71.68	$ 67.99
Company average	**$ 82.41**	$ 55.45	$ 53.65
Natural gas ($/mcf) (1) (2)			
North America	**$ 8.41**	$ 6.87	$ 6.77
North Sea	**$ 4.09**	$ 4.26	$ 2.66
Offshore West Africa	**$ 10.03**	$ 5.68	$ 5.37
Company average	**$ 8.39**	$ 6.85	$ 6.72
Company average ($/boe) (1) (2)	**$ 68.62**	$ 49.05	$ 47.92
Percentage of gross revenue (2) (excluding midstream revenue)			
Crude oil and NGLs	**68%**	62%	64%
Natural gas	**32%**	38%	36%

(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 increased 49% to average $82.41 per bbl for 2008 from $55.45 per bbl for 2007 (2006 – $53.65 per bbl). The increase in 2008 was primarily a result of higher WTI and Brent benchmark crude oil prices during most of the year and a narrower Heavy Differential, partially offset by the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

The Company's realized natural gas price increased 22% to average $8.39 per mcf for 2008 from $6.85 per mcf for 2007 (2006 – $6.72 per mcf). The increase in 2008 was primarily a result of increased benchmark prices due to increased industrial demand and lower liquefied natural gas imports into the US in the first half of 2008, partially offset by a significant reduction in industrial demand late in the year as a result of worldwide financial and economic events, and the impact of higher storage levels due to increased shale gas production in the US.

North America

North America realized crude oil prices increased 57% to average $77.42 per bbl for 2008 from $49.16 per bbl for 2007 (2006 – $46.52 per bbl). The increase in 2008 was due to increased WTI benchmark pricing and a narrower Heavy Differential, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

In North America, 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 2008, the Company contributed approximately 150,000 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.

North America realized natural gas prices increased 22% to average $8.41 per mcf for 2008 from $6.87 per mcf for 2007 (2006 – $6.77 per mcf), primarily related to fluctuations in benchmark prices due to the impact of weather and storage levels.

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

	2008	2007	2006
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	**$ 89.04**	$ 66.24	$ 63.09
Pelican Lake crude oil (C$/bbl)	**$ 76.91**	$ 46.29	$ 45.02
Primary heavy crude oil (C$/bbl)	**$ 74.91**	$ 43.77	$ 41.35
Thermal heavy crude oil (C$/bbl)	**$ 71.89**	$ 43.49	$ 40.98
Natural gas (C$/mcf)	**$ 8.41**	$ 6.87	$ 6.77

(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 increased 34% to average $100.31 per bbl for 2008 from $74.99 per bbl for 2007 (2006 – $72.62 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. Realized crude oil prices in the North Sea during 2008 benefited from the increased Brent benchmark pricing, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 37% to average $97.96 per bbl for 2008 from $71.68 per bbl for 2007 (2006 – $67.99 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. Realized crude oil prices in Offshore West Africa during 2008 benefited from the increased Brent benchmark pricing, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2008	2007	2006
Crude oil and NGLs (bbl/d)			
North America	**243,826**	246,779	235,253
North Sea	**45,274**	55,933	60,056
Offshore West Africa	**26,567**	28,520	36,689
	315,667	331,232	331,998
Natural gas (mmcf/d)			
North America	**1,472**	1,643	1,468
North Sea	**10**	13	15
Offshore West Africa	**13**	12	9
	1,495	1,668	1,492
Total barrels of oil equivalent (boe/d)	**564,845**	609,206	580,724
Product mix			
Light/medium crude oil and NGLs	**22%**	23%	26%
Pelican Lake crude oil	**6%**	6%	5%
Primary heavy crude oil	**16%**	15%	16%
Thermal heavy crude oil	**12%**	11%	11%
Natural gas	**44%**	45%	42%

Daily Production, Net of Royalties

	2008	2007	2006
Crude oil and NGLs (bbl/d)			
North America	**207,933**	210,769	205,382
North Sea	**45,182**	55,825	59,940
Offshore West Africa	**22,641**	26,012	35,212
	275,756	292,606	300,534
Natural gas (mmcf/d)			
North America	**1,225**	1,378	1,185
North Sea	**10**	13	15
Offshore West Africa	**11**	11	9
	1,246	1,402	1,209
Total barrels of oil equivalent (boe/d)	**483,541**	526,193	502,024

Daily production and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis. Production on an "after royalty" or "net" basis is also presented.

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 and thermal heavy crude oil.

Total production averaged 564,845 boe/d for 2008, a 7% decrease from 609,206 boe/d for 2007 (2006 – 580,724 boe/d).

Total production of crude oil and NGLs before royalties decreased 5% to 315,667 bbl/d for 2008 from 331,232 bbl/d for 2007 (2006 – 331,998 bbl/d). The decrease in crude oil and NGLs production from 2007 primarily reflected lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds and the sale of the Company's working interest in the B-Block Fields late in 2007, and in North America due to the cyclic nature of the Company's thermal production. Crude oil and NGLs production for 2008 was within the Company's previously issued guidance of 313,000 to 318,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 44% of the Company's total production in 2008. Total natural gas production before royalties decreased 10% to 1,495 mmcf/d for 2008 from 1,668 mmcf/d for 2007 (2006 – 1,492 mmcf/d). The decrease in natural gas production from 2007 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 2008 was within the Company's previously issued guidance of 1,492 to 1,506 mmcf/d.

For 2009, revised annual production is forecasted to average between 331,000 and 399,000 bbl/d of crude oil and NGLs and between 1,272 and 1,328 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for 2008 decreased 1% to average 243,826 bbl/d from 246,779 bbl/d for 2007 (2006 – 235,253 bbl/d). The decrease in production from 2007 was primarily due to the cyclic nature of the Company's thermal production.

North America natural gas production for 2008 decreased 10% to average 1,472 mmcf/d from 1,643 mmcf/d for 2007 (2006 – 1,468 mmcf/d). The decrease in natural gas production from 2007 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 Sea

North Sea crude oil production for 2008 was 45,274 bbl/d, a decrease of 19% from 55,933 bbl/d for 2007 (2006 – 60,056 bbl/d) due to increased planned maintenance, the sale of the Company's working interest in the B-Block Fields late in 2007, expected production declines and delays in development projects.

Offshore West Africa

Offshore West Africa crude oil production for 2008 decreased 7% to 26,567 bbl/d from 28,520 bbl/d for 2007 (2006 – 36,689 bbl/d). Production decreased in 2008 due to expected production declines, partially offset by a full year of production at the recently completed West Espoir development and restoration of certain of the shut-in production at the Baobab Field during the fourth quarter of 2008.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related crude oil volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	2008	2007	2006
North America, related to pipeline fill	**761,351**	1,097,526	1,097,526
North Sea, related to timing of liftings	**558,904**	1,032,723	910,796
Offshore West Africa, related to timing of liftings	**609,444**	8,578	113,774
	1,929,699	2,138,827	2,122,096

During 2008, the North America pipeline fill was reduced, increasing cash flow from operations by approximately $18 million.

In addition, during 2008, net production of approximately 127,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at December 31, 2008. Notwithstanding the overall increase in inventory, cash flow from operations increased by approximately $5 million, as the increase in cash flow from additional sales volumes in the North Sea more than offset the decrease in cash flow from lower sales volumes in Offshore West Africa due to the timing of liftings.

ROYALTIES

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 11.99**	$ 7.19	$ 5.86
North Sea	**$ 0.21**	$ 0.14	$ 0.13
Offshore West Africa	**$ 14.81**	$ 6.40	$ 2.81
Company average	**$ 10.48**	$ 5.94	$ 4.48
Natural gas ($/mcf) (1)			
North America	**$ 1.47**	$ 1.12	$ 1.31
Offshore West Africa	**$ 1.52**	$ 0.51	$ 0.22
Company average	**$ 1.46**	$ 1.11	$ 1.29
Company average ($/boe) (1)	**$ 9.78**	$ 6.26	$ 5.89
Percentage of revenue (2)			
Crude oil and NGLs	**13%**	11%	8%
Natural gas	**17%**	16%	19%
Boe	**14%**	13%	12%

(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 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 NRF 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 NRF for conventional crude oil and natural gas are to operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

Crude oil and NGLs royalties for 2008 continued to reflect strong realized crude oil prices and averaged approximately 15% of gross revenues for 2008 and 2007 (2006 – 13%). North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 15% of gross revenue for 2009.

Natural gas royalties per mcf generally fluctuate with natural gas prices and well productivity. Natural gas royalties averaged approximately 18% of gross revenues for 2008 compared to 16% for 2007 (2006 – 19%), primarily due to increased benchmark natural gas prices. North America natural gas royalties per mcf are anticipated to average 14% to 18% of gross revenue for 2009.

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

Offshore West Africa production in both Côte d'Ivoire and Gabon is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the 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 Government State Oil Companies. 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 between royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Fields in Côte d'Ivoire were fully recovered in early 2007, increasing royalty rates and current income taxes in accordance with the terms of the PSCs.

Royalty rates as a percentage of revenue averaged approximately 15% for 2008 compared to 9% for 2007 (2006 – 4%). The increase in royalty rates from 2007 was due to the impact of the Company's full recovery of its capital investment in the Espoir Fields in 2007 and the resulting increase in profit oil on which the Government's entitlement is based. The increase was compounded by the impact of the reduction in the Côte d'Ivoire corporate income tax rate enacted early in 2008, which had the effect of increasing the allocation of the Government's share of profit oil to royalties. Offshore West Africa royalty rates are anticipated to average 6% to 10% of gross revenue for 2009, reflecting a lower price environment and the Espoir Field contributing a lower proportion of the total Offshore West Africa production.

PRODUCTION EXPENSE

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 14.96**	$ 12.26	$ 11.73
North Sea	**$ 26.29**	$ 20.78	$ 17.57
Offshore West Africa	**$ 10.29**	$ 8.32	$ 7.45
Company average	**$ 16.26**	$ 13.34	$ 12.29
Natural gas ($/mcf) (1)			
North America	**$ 1.00**	$ 0.90	$ 0.81
North Sea	**$ 2.51**	$ 2.17	$ 1.40
Offshore West Africa	**$ 1.61**	$ 1.48	$ 1.19
Company average	**$ 1.02**	$ 0.91	$ 0.82
Company average ($/boe) (1)	**$ 11.79**	$ 9.75	$ 9.14

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

North America

North America crude oil and NGLs production expense for 2008 increased 22% to $14.96 per bbl from $12.26 per bbl for 2007 (2006 – $11.73 per bbl). The increase in production expense per bbl from 2007 was primarily a result of the higher cost of natural gas for fuel for the Company's thermal operations and increased property tax and power costs. The increase was also a result of the impact of lower production volumes on the fixed cost portion of production costs.

North America natural gas production expense for 2008 increased 11% to $1.00 per mcf from $0.90 per mcf for 2007 (2006 – $0.81 per mcf). The increase in production expense per mcf from 2007 was primarily a result of the Company's strategic reduction in natural gas drilling activity, decreasing natural gas production throughout 2008 and increasing production expense per mcf on the fixed cost portion of production costs.

Production expense per boe for 2009 is anticipated to increase as a result of an overall reduction in budgeted volumes for 2009, while fixed costs, such as property taxes and lease rentals, are forecasted to continue to escalate.

North Sea

North Sea crude oil production expense increased on a per barrel basis from 2007 primarily due to lower production volumes on a relatively fixed operating cost base as well as due to higher planned maintenance costs.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per barrel basis from 2007 primarily due to lower production volumes on a relatively fixed operating cost base.

MIDSTREAM

($ millions)	**2008**	2007	2006
Revenue	**$ 77**	$ 74	$ 72
Production expense	**25**	22	23
Midstream cash flow	**52**	52	49
Depreciation	**8**	8	8
Segment earnings before taxes	**$ 44**	$ 44	$ 41

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.

DEPLETION, DEPRECIATION AND AMORTIZATION [1]

($ millions, except per boe amounts) [2]	2008	2007	2006
North America [3]	**$ 2,226**	$ 2,350	$ 1,897
North Sea	**317**	340	297
Offshore West Africa	**132**	165	189
Expense	**$ 2,675**	$ 2,855	$ 2,383
$/boe	**$ 12.97**	$ 12.84	$ 11.27

(1) DD&A excludes depreciation on midstream assets.
(2) Amounts expressed on a per unit basis are based on sales volumes.
(3) Amounts include the impact of intersegment eliminations.

Depletion, Depreciation and Amortization ("DD&A") expense for 2008 decreased 6% to $2,675 million from $2,855 million for 2007 (2006 – $2,383 million), primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) [1]	2008	2007	2006
North America	**$ 42**	$ 38	$ 35
North Sea	**27**	30	31
Offshore West Africa	**2**	2	2
Expense	**$ 71**	$ 70	$ 68
$/boe	**$ 0.34**	$ 0.32	$ 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 2008 was comparable to 2007.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) [1]	2008	2007	2006
Expense	**$ 180**	$ 208	$ 180
$/boe	**$ 0.87**	$ 0.93	$ 0.85

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

Administration expense for 2008 decreased from 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program, as well as due to decreased office lease costs.

STOCK-BASED COMPENSATION

($ millions)	2008	2007	2006
(Recovery) expense	**$ (52)**	$ 193	$ 139

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 $52 million ($38 million after-tax) stock-based compensation recovery during 2008 due to a 33% decrease in the Company's share price for the year ended December 31, 2008 (December 31, 2008 – C$48.75; December 31, 2007 – C$72.58; December 31, 2006 – C$62.15; December 31, 2005 – C$57.63), offset by the impact of normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the year. 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. The liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the year, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the year ended December 31, 2008, the Company recorded a $23 million recovery on previously capitalized stock-based compensation on the Horizon Project (2007 – $58 million capitalized; 2006 – $79 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, 2008. 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, 2008, the Company paid $207 million for stock options surrendered for cash settlement (2007 – $375 million; 2006 – $264 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2008	2007	2006
Expense, gross	$ 609	$ 632	$ 336
Less: capitalized interest, Horizon Project	481	356	196
Expense, net	$ 128	$ 276	$ 140
$/boe	$ 0.62	$ 1.24	$ 0.66
Average effective interest rate	5.1%	5.5%	5.7%

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

Gross interest expense and the Company's average effective interest rate decreased from 2007 primarily due to a decrease in short term borrowing rates during the last half of 2008 and the impact of the stronger Canadian dollar during the first half of 2008.

On commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase and interest expense will increase accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. The Company's risk management program is not used for speculative purposes.

($ millions)	2008	2007	2006
Crude oil and NGLs financial instruments	$ 2,020	$ 505	$ 1,395
Natural gas financial instruments	(21)	(343)	(70)
Foreign currency contracts	(139)	–	–
Realized loss	$ 1,860	$ 162	$ 1,325
Crude oil and NGLs financial instruments	$ (3,104)	$ 1,244	$ (736)
Natural gas financial instruments	16	156	(260)
Foreign currency contracts	(2)	–	(17)
Unrealized (gain) loss	$ (3,090)	$ 1,400	$ (1,013)
Net (gain) loss	$ (1,230)	$ 1,562	$ 312

The net realized loss (gain) from crude oil and natural gas financial instruments would have decreased (increased) the Company's average realized prices as follows:

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)	$ 17.45	$ 4.18	$ 11.57
Natural gas ($/mcf) (1)	$ (0.04)	$ (0.56)	$ (0.13)

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

Complete details related to outstanding derivative financial instruments at December 31, 2008 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, 2008.

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 gain of $3,090 million ($2,112 million after-tax) on its risk management activities for the year ended December 31, 2008 (2007 – $1,400 million unrealized loss, $977 million after-tax; 2006 – $1,013 million unrealized gain, $674 million after-tax).

FOREIGN EXCHANGE

($ millions)	2008	2007	2006
Net realized (gain) loss	$ (114)	$ 53	$ (12)
Net unrealized loss (gain) (1)	832	(524)	134
Net loss (gain)	$ 718	$ (471)	$ 122

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

The Company's North Sea operations are classified as self-sustaining for the purposes of foreign currency translation. The North Sea operations are initially measured in US dollars and then translated to Canadian dollars using the current rate method, whereby assets and liabilities are translated into Canadian dollars using the exchange rate in effect at the balance sheet date, while revenue and expenses are translated into Canadian dollars using the monthly average exchange rate. Foreign currency gains or losses arising on the translation of non-US dollar monetary assets and liabilities are included in net earnings while subsequent gains or losses arising on translation to Canadian dollars are deferred and included in accumulated other comprehensive income.

During 2008, the Company determined that its operations in Offshore West Africa were now operationally and financially independent and the current rate method of translation was prospectively adopted for translation of the financial statements of the Offshore West African subsidiaries as at December 31, 2008. Prior to this determination, the Company's Offshore West Africa foreign operations were classified as integrated for the purposes of foreign currency translation, and accordingly, Offshore West Africa foreign operations and foreign currency transactions and balances held in North America were directly translated into Canadian dollars using the temporal method. All related foreign exchange gains or losses were included in net earnings.

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 loss in 2008 was primarily related to the weakening of the 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 loss for the year ended December 31, 2008 was an unrealized gain of $449 million related to the impact of cross currency swap hedges. The net realized foreign exchange gain for 2008 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$0.8166 compared to US$1.0120 at December 31, 2007 (December 31, 2006 – US$0.8581).

TAXES

($ millions, except income tax rates)	**2008**	2007	2006
Current	**$ 245**	$ 121	$ 219
Deferred	**(67)**	44	37
Taxes other than income tax	**$ 178**	$ 165	$ 256
North America	**$ 33**	$ 96	$ 143
North Sea	**340**	210	30
Offshore West Africa	**128**	74	49
Current income tax	**501**	380	222
Future income tax	**1,607**	(456)	652
	2,108	(76)	874
Income tax rate and other legislative changes (1) (2) (3)	**41**	864	395
	$ 2,149	$ 788	$ 1,269
Effective income tax rate before income tax rate and other legislative changes	**30.3%**	31.1%	37.3%

(1) 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.
(2) 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.
(3) Includes the effect of the following:
- a one time expense of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea enacted in 2006.
- a one time recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan corporate income tax rate reductions enacted in 2006.
- a one time recovery of $67 million due to Côte d'Ivoire, Offshore West Africa corporate income tax rate reductions enacted in 2006.

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, North America and North Sea current income taxes will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

For 2009, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $20 million to $50 million and in the North Sea of $350 million to $450 million.

NET CAPITAL EXPENDITURES [1]

($ millions)	2008	2007	2006
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions) [2]	**$ 336**	$ (39)	$ 4,733
Land acquisition and retention	**86**	95	210
Seismic evaluations	**107**	124	130
Well drilling, completion and equipping	**1,664**	1,642	2,340
Production and related facilities	**1,282**	1,205	1,314
Total net reserve replacement expenditures	**3,475**	3,027	8,727
Horizon Project:			
Phase 1 construction costs	**2,732**	2,740	2,768
Phase 1 operating and capital inventory	**87**	–	–
Phase 1 commissioning costs	**277**	–	–
Phases 2/3 costs	**336**	124	79
Capitalized interest, stock-based compensation and other	**480**	437	338
Total Horizon Project [3]	**3,912**	3,301	3,185
Midstream	**9**	6	12
Abandonments [4]	**38**	71	75
Head office	**17**	20	26
Total net capital expenditures	**$ 7,451**	$ 6,425	$ 12,025
By segment			
North America	**$ 2,344**	$ 2,428	$ 7,936
North Sea	**319**	439	646
Offshore West Africa	**811**	159	134
Other	**1**	1	11
Horizon Project	**3,912**	3,301	3,185
Midstream	**9**	6	12
Abandonments [4]	**38**	71	75
Head office	**17**	20	26
Total	**$ 7,451**	$ 6,425	$ 12,025

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Net expenditures for the Horizon Project also include the impact of intersegment eliminations.
(4) 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 2008 were $7,451 million compared to $6,425 million for 2007 (2006 – $12,025 million). Excluding the ACC acquisition, net capital expenditures were $7,270 million for 2006. Capital expenditures in 2008 primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, Primrose East, and Gabon, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

During 2008, the Company drilled a total of 1,121 net wells consisting of 269 natural gas wells, 682 crude oil wells, 131 stratigraphic test and service wells, and 39 wells that were dry. This compared to 1,322 net wells drilled for 2007 (2006 – 1,738 net wells). The Company achieved an overall success rate of 96% for 2008, excluding the stratigraphic test and service wells (2007 – 91%; 2006 – 91%).

North America

North America, excluding the Horizon Project, accounted for approximately 32% of the total capital expenditures for the year ended December 31, 2008 compared to approximately 39% for 2007 (2006 – 67%).

During 2008, the Company targeted 280 net natural gas wells, including 27 wells in Northeast British Columbia, 104 wells in the Northern Plains region, 70 wells in Northwest Alberta, and 79 wells in the Southern Plains region. The Company also targeted 704 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 415 primary heavy crude oil wells, 110 Pelican Lake crude oil wells, 74 thermal crude oil wells and 7 light crude oil wells were drilled. Another 98 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant differences in relative commodity prices between crude oil and natural gas throughout most of 2008, 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 2007 and 2008 and as a result of royalty changes under the Alberta NRF, natural gas drilling activities have been reduced to manage overall capital spending. 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 2008, the Company drilled 74 thermal oil wells, 2 water source wells, and 19 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2008 was approximately 65,000 bbl/d (2007 – 64,000 bbl/d; 2006 – 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. Subsequent to December 31, 2008, operational issues on one of the pads has caused steaming to cease on all well pads in the Primrose East project area and the Company is working on rectifying the issues.

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 will be impacted by environmental regulations and their associated costs. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout 2008. Drilling consisted of 110 horizontal crude oil wells, with plans to drill 58 additional horizontal crude oil wells in 2009. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d in 2008 (2007 – 34,000 bbl/d; 2006 – 30,000 bbl/d).

For 2009, the Company's overall drilling activity in North America is expected to comprise approximately 142 natural gas wells and 465 crude oil wells, excluding stratigraphic and service wells.

Horizon Project

The Company continued the construction, commissioning and staged start up of the Horizon Project, with first production of synthetic crude oil from Phase 1 achieved February 28, 2009, representing a major milestone. Currently, the Company is filling all product tanks in preparation for blending and pipeline shipment.

All major components have been completed and are fully operational, with the exception of the Distillate Hydrotreating Plant (Plant 42). The Naphtha and Gas Oil Hydrotreaters (Plants 41 and 43 respectively) are fully operational and currently capable of producing approximately 55,000 bbl/d. Upon completion of Plant 42, the focus will be on reaching full production capacity of 110,000 bbl/d. Plant 42 has now been turned over to operations for commissioning and is targeted to be operational by the end of April 2009, subject to any unforeseen start up issues.

During the initial stages of the ramp-up of production, the production volumes will fluctuate on a weekly basis until the end of the second quarter of 2009 when the Company expects to see a steady ramp up to full production by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.

Phase 1 of the Horizon Project was designed, engineered, and constructed in an extremely volatile and inflationary business environment with final construction costs totaling approximately $9.7 billion. Subsequent planned expansion through Phases 2/3, further broken down into a series of four Tranches, are being reprofiled with the goal of attaining better cost management.

North Sea

In 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2008, 4.1 net wells were drilled, including 0.9 net water injectors, with an additional 1.2 net wells drilling at year end. Specifically, two production wells were completed at Murchison and one production well was completed at Ninian, with an additional production well in progress at Ninian at year end. The Company also delivered one water injection well at Ninian and further increased volumes injected into the Ninian reservoir.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried out maintenance turnarounds at all five installations during the year. Within the Murchison turnaround the Company successfully implemented a new control system, which has resulted in improved platform uptime.

Offshore West Africa

During 2008, 4.1 net wells were drilled with 0.9 net wells drilling at year end.

Development drilling on West Espoir was completed in early 2008, on budget and on time. At the Baobab Field, the Company delivered three new wells from the drilling program, with a fourth well due to be completed in the second quarter of 2009.

At the 90% owned and operated Olowi Field in offshore Gabon, the Conductor Supported Platform was installed, construction was completed on the FPSO, which arrived on location in February 2009, and construction continued on the wellhead towers and subsea facilities. First crude oil is targeted for late in the first quarter or early in the second quarter of 2009.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2008	2007	2006
Working capital (deficit) [(1)]	$ 392	$ (1,382)	$ (832)
Long-term debt [(2) (3)]	$ 13,016	$ 10,940	$ 11,043
Shareholders' equity			
Share capital	$ 2,768	$ 2,674	$ 2,562
Retained earnings	15,344	10,575	8,141
Accumulated other comprehensive income (loss)	262	72	(13)
Total	$ 18,374	$ 13,321	$ 10,690
Debt to book capitalization [(3) (4)]	41%	45%	51%
Debt to market capitalization [(3) (5)]	33%	22%	25%
After tax return on average common shareholders' equity [(6)]	33%	22%	27%
After tax return on average capital employed [(3) (7)]	19%	12%	17%

(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 (2008 – $420 million; 2007 and 2006 – $nil).
(3) Long-term debt at December 31, 2008 and 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs. Amounts for 2006 were not adjusted for these items.
(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 $10,678 million in average capital employed related to the Horizon Project (2007 – $7,001 million; 2006 – $3,760 million).

At December 31, 2008, 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 ongoing worldwide financial and economic events have resulted in a significant tightening of the availability and cost of new sources of liquidity including bank credit facilities and funds derived from debt capital markets. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short-, medium- and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its 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. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

On an ongoing basis, the Company continues to focus on the following areas:

- Monitoring cash flow from operations, which is the primary source of funds;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages;
- Monitoring credit markets, governments, world banks and the Company's bank syndicates to identify associated risks and exposures;
- Maintaining an active commodity risk management program that manages exposure to crude oil and natural gas price volatility. The Company believes this is an effective tool to manage short- and medium-term changes in spot commodity prices. The Company also monitors its commodity risk management counterparties to ensure they are in position to settle obligations within the contractually agreed terms of settlement;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of default; and
- Monitoring the Company's 2009 capital and operating plans to provide the required flexibility to deal with commodity price volatility, commitments in respect of capital and operating expenditures, and commitments to retire its non-revolving bank credit facility maturing in October 2009. The Company actively manages the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner. The Company continued the construction, commissioning and staged start up of the Horizon Project, with first production of synthetic crude oil from Phase 1 achieved February 28, 2009.

At December 31, 2008, the Company had $2,082 million of available credit under its bank credit facilities, which together with cash flow from operating activities to be generated in 2009 supported by its commodity risk management program and the ability to actively manage the capital expenditure programs, is forecasted to be sufficient to repay the $2,350 million non-revolving bank credit facility maturing October 2009. Further, the Company's current debt ratings are BBB (high) with a negative 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, 2008 are discussed below and in note 5 to the Company's audited annual consolidated financial statements.

At December 31, 2008, the Company's working capital was $392 million, excluding the current portion of long-term debt and including both the current portion of the net mark-to-market asset for risk management derivative financial instruments of $1,851 million and the current portion of the stock-based compensation liability of $159 million, together with related future income tax liabilities of $585 million. The cash settlement amount of the risk management 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, 2008. The settlement of the stock-based compensation liability is dependant upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender.

Long-term debt was $13,016 million at December 31, 2008, resulting in a debt to book capitalization level of 41% as at December 31, 2008 (December 31, 2007 – 45%; December 31, 2006 – 51%). This ratio is near the midpoint of the 35% to 45% range targeted by management, including the impact of capital spending on the Horizon Project. 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 2009 and 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

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, 2008, in accordance with the policy, approximately 6% of budgeted crude oil volumes were hedged using collars for 2009 and approximately 33% of budgeted natural gas volumes were hedged for the first quarter of 2009. In addition, 92,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$100.00 per bbl.

The Company had the following net commodity derivative financial instruments outstanding as at December 31, 2008:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars	Jan 2009 – Dec 2009	25,000 bbl/d	US$70.00 – US$111.56	WTI
	Apr 2009 – Jun 2009	4,000 bbl/d	US$70.00 – US$90.00	WTI
Crude oil puts	Jan 2009 – Dec 2009	92,000 bbl/d	US$100.00	WTI
Natural gas				
Natural gas price collars (1)	Jan 2009 – Mar 2009	500,000 GJ/d	C$6.00 – C$8.63	AECO

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 – C$8.00 natural gas AECO collars for the period January to December 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.

In addition to the financial derivatives noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 2009.

LONG-TERM DEBT

The Company's long-term debt of $13,016 million at December 31, 2008 was comprised of drawings under its bank credit facilities and debt issuances under medium and long-term unsecured notes.

Bank Credit Facilities

As at December 31, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009, as discussed below;
- 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.

During 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were also extended and now mature June 2012. Both 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.

In conjunction with the closing of the acquisition of ACC in November 2006, the Company executed a $3,850 million, non-revolving syndicated credit facility maturing October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing borrowing capacity under its other long-term bank credit facilities, which were $2,050 million at December 31, 2008, supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2008.

Medium-Term Notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2007, $125 million of the 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior Unsecured Notes

The adjustable rate senior unsecured notes bear interest at 6.54%, with the final annual principal repayment of US$31 million due in May 2009. During 2008 and 2007, US$31 million of the senior unsecured notes were repaid each year.

US Dollar Debt Securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a 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. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

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

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

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 from the date of termination of the interest rate swaps for subsequent changes in fair value. 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.

During 2007, The Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on US dollar denominated long-term debt are now recognized in the consolidated statements of earnings.

SHARE CAPITAL

As at December 31, 2008, there were 540,991,000 common shares outstanding and 30,962,000 stock options outstanding. As at March 3, 2009, the Company had 541,149,000 common shares outstanding and 30,285,000 stock options outstanding.

The Company did not renew the Normal Course Issuer Bid during 2008. During 2007 and 2008, the Company did not purchase any common shares for cancellation (2006 – 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million).

In March 2009, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.42 per common share for 2009. The increase represents a 5% increase from the prior year. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In February 2008, an increase in the annual dividend paid by the Company was approved to $0.40 per common share for 2008. The increase represented an 18% increase from 2007.

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, 2008, 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, 2008:

($ millions)	2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124	$ 1,175
Offshore equipment operating lease	$ 175	$ 145	$ 144	$ 116	$ 117	$ 398
Offshore drilling	$ 251	$ 62	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6	$ 4,443
Long-term debt (2)	$ 2,385	$ 400	$ 490	$ 429	$ 890	$ 6,707
Interest expense (3)	$ 610	$ 565	$ 543	$ 490	$ 428	$ 5,992
Office lease	$ 25	$ 29	$ 23	$ 2	$ 2	$ 1
Other	$ 321	$ 180	$ 17	$ 12	$ 8	$ 19

(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 2009 – 2013 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 $1,725 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, 2008.

LEGAL PROCEEDINGS

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 construction claims related to the Horizon Project. 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, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves[1] and prepare Evaluation Reports on these reserves. The Company has been granted an exemption from certain of the 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 for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year end constant prices and 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 Company has elected to provide the net present value[2] of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. The Company has also elected to provide both proved and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as additional voluntary information, which is disclosed in the Company's Annual Information Form.

(1) Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves.

(2) Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment liabilities have been applied.

The following tables summarize the Company's proved conventional crude oil and natural gas reserves, net of royalties, as at December 31, 2008 and 2007:

Crude oil and NGLs (mmbbl)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net conventional proved reserves				
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	**948**	**256**	**142**	**1,346**

The Company's net proved conventional crude oil reserves at December 31, 2008 totaled 1,346 mmbbl. Approximately 88% of production was replaced by reserve additions during 2008. Extensions and discoveries resulting from exploration and development activities amounted to 51 mmbbl, while net positive revisions amounted to 11 mmbbl.

Natural gas (bcf)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net conventional proved reserves				
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**

The Company's net proved conventional natural gas reserves at December 31, 2008 totaled 3,684 bcf. Approximately 104% of production was replaced by reserve additions during 2008. Extensions and discoveries resulting from exploration and development activities amounted to 140 bcf, while net positive revisions amounted to 202 bcf.

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate Phase 1 to Phase 3 of the Company's Horizon Project and prepare an Evaluation Report on the Company's proved, as well as proved and probable oil sands mining reserves. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year end constant pricing and have been disclosed separately from the Company's conventional proved and proved and probable crude oil, NGLs and natural gas reserves.

Synthetic crude oil reserves [1]

Net reserves, after royalties (mmbbl)	**2008**	2007
Proved	**1,946**	1,761
Proved and probable	**2,944**	2,680

(1) SCO reserves are based on the upgrading of bitumen using technologies implemented at the Horizon Project.

The net proved SCO reserves increased by 185 mmbbl, while net proved and probable SCO reserves increased by 264 mmbbl. The increases are primarily due to a low constant dollar crude oil price, deferring project payout and thereby reducing royalties paid.

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 conventional crude oil, NGLs and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

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 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; 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 nonperformance 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 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 will 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 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. The Company's strategy employs an Environmental Management Plan (the "Plan"). Details of the Plan and the 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 reduction and conservation program;
- A program to replace the majority of fresh water for steaming with brackish water;
- 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; and
- Continued evaluation of new technologies to reduce environmental impacts.

The Company has also established stringent operating standards in four areas:

- Implementing cost effective ways of reducing GHG emissions per unit of production;
- Exercising care with respect to all waste produced through effective waste management plans;
- Using water-based, environmentally friendly drilling muds whenever possible; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

For 2008, the Company's capital expenditures included $38 million for abandonment expenditures (2007 – $71 million; 2006 – $75 million).

The Company's estimated undiscounted ARO at December 31, 2008 was as follows:

Estimated ARO, undiscounted ($ millions)	2008	2007
North America, including Horizon Project	**$ 3,165**	$ 3,038
North Sea	**1,216**	1,286
Offshore West Africa	**93**	102
	4,474	4,426
North Sea PRT recovery	**(529)**	(555)
	$ 3,945	$ 3,871

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 $529 million (2007 – $555 million; 2006 – $625 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 $3,945 million (2007 – $3,871 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. 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 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 2010 to address industrial GHG emissions. 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. Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012. 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.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is 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, 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 legislation 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 judgements, 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

The Company follows 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 single-day, year-end prices and costs ("constant dollar pricing") 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. No ceiling test impairments were recognized under Canadian GAAP at December 31, 2008, as future net revenues exceeded capitalized costs. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on constant dollar pricing 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 $6,164 million for US GAAP purposes.

The US GAAP ceiling test is based on constant dollar pricing and is highly sensitive to differences in benchmark pricing and the Heavy Differential in effect at year end as opposed to pricing throughout the year. As the Company's crude oil production is weighted towards heavier grades of crude oil, which have historically traded at lower prices at year end due to normal seasonality, constant dollar pricing in effect at year end is generally not representative of average pricing realized throughout the year. Had the US GAAP ceiling test at December 31, 2008 been prepared using average realized pricing throughout 2008, rather than constant dollar pricing, and assuming no other changes in reserves, operating costs, or future development costs, the Company would not have recognized a ceiling test impairment loss in the current year for US GAAP purposes.

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 judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing and amount 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 is recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset the Company is required to settle as a result of 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 6.7%. 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 Project 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 judgements 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 judgements 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 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. 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 judgements relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (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 judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

CONTROL ENVIRONMENT

The Company's management, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2008, 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, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance also performed an assessment of internal control over financial reporting as at December 31, 2008, 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 2008 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance 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

Effective January 1, 2008, the Company adopted the following accounting and disclosure standards issued by the CICA:

Capital Disclosures

- Section 1535 – "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affects disclosure only and did not impact the Company's accounting for capital.

Inventories

- Section 3031 – "Inventories" replaces Section 3030 – "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.

Financial Instruments

- Section 3862 – "Financial Instruments – Disclosure" and Section 3863 "Financial Instruments – Presentation" replace Section 3861 – "Financial Instruments – Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affect disclosures only and did not impact the Company's accounting for financial instruments.

Effective January 1, 2009, the Company will adopt the following new accounting standard issued by the CICA:

Goodwill and Intangible Assets

- Section 3064 – "Goodwill and Intangible Assets" replaces 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" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. Adoption of the new standard may impact the Company's future capitalization of certain costs during the development and start-up of large development projects.

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 commenced its IFRS conversion project in 2008 and has established a formal 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 Senior Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project consists of the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – development 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 phase. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, impairment testing, capitalized interest and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is currently performing the necessary research to develop and document IFRS policies to address the major differences noted. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, IFRS is expected to change prior to adoption in 2011, and the impact of these potential changes is not known. Included in the potential IFRS changes is an exposure draft issued in September 2008 by the IASB that proposes transition rules for oil and gas companies following full cost accounting. The proposed transition rule would allow full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account as at the date of conversion without requiring retroactive adjustment. The Company intends to adopt the transition rule if it is approved.

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 2009 to average between 331,000 bbl/d and 399,000 bbl/d of crude oil and NGLs and between 1,272 mmcf/d and 1,328 mmcf/d of natural gas.

The forecasted capital expenditures in 2009 are currently expected to be as follows:

($ millions)	2009 Forecast
Conventional crude oil and natural gas	
North America natural gas	$ 589
North America crude oil and NGLs	1,138
North Sea	141
Offshore West Africa	553
Property acquisitions, dispositions and midstream	109
	$ 2,530
Horizon Project	
Phase 1 – Construction	$ 180
Phase 1 – Operating and capital inventory	43
Phase 1 – Commissioning costs	183
Phase 2/3 – Tranche 2	121
Sustaining capital	94
Capitalized interest and other costs	41
	$ 662
Total	$ 3,192

North America Natural Gas

The 2009 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)	2009 Forecast
Coal bed methane and shallow natural gas	30
Conventional natural gas	66
Cardium natural gas	9
Deep natural gas	37
Total	142

The Company has reduced 2009 natural gas drilling in Alberta due to the anticipated future impact of royalty changes effective January 1, 2009.

North America Crude Oil and NGLs

The 2009 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)	2009 Forecast
Conventional primary heavy crude oil	317
Thermal heavy crude oil	70
Light crude oil	20
Pelican Lake crude oil	58
Total	465

Horizon Project

During the initial stages of the ramp-up of production, the production volumes will fluctuate on a weekly basis until the end of the second quarter of 2009 when the Company expects to see a steady ramp up to full production capacity of 110,000 bbl/d by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.

North Sea

The 2009 capital forecast for the North Sea includes drilling 0.9 net platform wells with focus on building drilling and workover inventory for 2010.

Offshore West Africa

The 2009 capital forecast for Offshore West Africa anticipates spending $80 million to complete Phase 2 of the development of the Baobab Field in Côte d'Ivoire. The Company is targeting the fourth well to be completed in the second quarter of 2009.

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 2008, 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	$ 112	$ 0.21	$ 84	$ 0.16
Including financial derivatives	$ 66	$ 0.12	$ 48	$ 0.09
Natural gas – AECO C$0.10/mcf [1]				
Excluding financial derivatives	$ 38	$ 0.07	$ 28	$ 0.05
Including financial derivatives	$ 38	$ 0.07	$ 28	$ 0.05
Volume changes				
Crude oil – 10,000 bbl/d	$ 87	$ 0.16	$ 38	$ 0.07
Natural gas – 10 mmcf/d	$ 18	$ 0.03	$ 7	$ 0.01
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 89 – 92	$ 0.17	$ 8 – 9	$ 0.02
Interest rate change – 1%	$ 32	$ 0.06	$ 32	$ 0.06

(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, 2008.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2008	2007	2006
Crude oil and NGLs (bbl/d)							
North America	248,960	245,616	239,973	240,831	243,826	246,779	235,253
North Sea	49,568	45,830	42,760	42,991	45,274	55,933	60,056
Offshore West Africa	28,689	27,631	24,237	25,748	26,567	28,520	36,689
Total	327,217	319,077	306,970	309,570	315,667	331,232	331,998
Natural gas (mmcf/d)							
North America	1,513	1,501	1,467	1,405	1,472	1,643	1,468
North Sea	11	10	9	10	10	13	15
Offshore West Africa	14	15	14	12	13	12	9
Total	1,538	1,526	1,490	1,427	1,495	1,668	1,492
Barrels of oil equivalent (boe/d)							
North America	501,061	495,836	484,542	475,089	489,081	520,564	479,891
North Sea	51,404	47,545	44,309	44,623	46,956	58,099	62,558
Offshore West Africa	31,023	30,056	26,505	27,687	28,808	30,543	38,275
Total	583,488	573,437	555,356	547,399	564,845	609,206	580,724

PER UNIT RESULTS (1)

	Q1	Q2	Q3	Q4	2008	2007	2006
Crude oil and NGLs ($/bbl)							
Sales price (2)	$ 78.99	$ 103.73	$ 102.30	$ 45.81	$ 82.41	$ 55.45	$ 53.65
Royalties	8.70	14.82	14.17	4.49	10.48	5.94	4.48
Production expense	14.81	16.39	17.61	16.33	16.26	13.34	12.29
Netback	$ 55.48	$ 72.52	$ 70.52	$ 24.99	$ 55.67	$ 36.17	$ 36.88
Natural gas ($/mcf)							
Sales price (2)	$ 7.77	$ 9.89	$ 8.82	$ 7.03	$ 8.39	$ 6.85	$ 6.72
Royalties	1.35	1.86	1.55	1.08	1.46	1.11	1.29
Production expense	1.03	0.94	1.05	1.06	1.02	0.91	0.82
Netback	$ 5.39	$ 7.09	$ 6.22	$ 4.89	$ 5.91	$ 4.83	$ 4.61
Barrels of oil equivalent ($/boe)							
Sales price (2)	$ 65.09	$ 84.88	$ 80.60	$ 43.84	$ 68.62	$ 49.05	$ 47.92
Royalties	8.43	13.26	12.06	5.37	9.78	6.26	5.89
Production expense	11.02	11.60	12.52	12.05	11.79	9.75	9.14
Netback	$ 45.64	$ 60.02	$ 56.02	$ 26.42	$ 47.05	$ 33.04	$ 32.89

(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.

NETBACK ANALYSIS

($/boe) (1)	2008	2007	2006
Sales price (2)	$ 68.62	$ 49.05	$ 47.92
Royalties	9.78	6.26	5.89
Production expense (3)	11.79	9.75	9.14
Netback	47.05	33.04	32.89
Midstream contribution (3)	(0.25)	(0.23)	(0.23)
Administration	0.87	0.93	0.85
Interest, net	0.62	1.24	0.66
Realized risk management loss	8.99	0.73	6.27
Realized foreign exchange loss (gain)	(0.55)	0.24	(0.06)
Taxes other than income tax – current	1.18	0.54	1.04
Current income tax – North America	0.15	0.43	0.68
Current income tax – North Sea	1.64	0.95	0.14
Current income tax – Offshore West Africa	0.62	0.33	0.23
Cash flow	$ 33.78	$ 27.88	$ 23.31

(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) Excluding inter-segment eliminations.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2008	2007
TSX – C$						
Trading Volume (thousands)	**134,421**	**145,018**	**186,906**	**213,393**	**679,738**	429,034
Share Price ($/share)						
High	**$ 76.80**	**$ 111.30**	**$ 104.83**	**$ 72.89**	**$ 111.30**	$ 80.02
Low	**$ 58.88**	**$ 68.08**	**$ 64.40**	**$ 34.19**	**$ 34.19**	$ 52.45
Close	**$ 70.27**	**$ 100.84**	**$ 73.00**	**$ 48.75**	**$ 48.75**	$ 72.58
Market capitalization as at December 31 ($ millions)					**$ 26,373**	$ 39,174
Shares outstanding (thousands)					**540,991**	539,729
NYSE – US$						
Trading Volume (thousands)	**157,781**	**190,756**	**292,659**	**326,032**	**967,228**	486,266
Share Price ($/share)						
High	**$ 78.43**	**$ 109.32**	**$ 103.40**	**$ 68.87**	**$ 109.32**	$ 87.17
Low	**$ 57.07**	**$ 66.21**	**$ 61.82**	**$ 26.43**	**$ 26.43**	$ 44.56
Close	**$ 68.26**	**$ 100.25**	**$ 68.46**	**$ 39.98**	**$ 39.98**	$ 73.14
Market capitalization as at December 31($ millions)					**$ 21,629**	$ 39,476
Shares outstanding (thousands)					**540,991**	539,729

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, 2008; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2008.

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 of non-management 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 & CHIEF OPERATING OFFICER

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

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

MARCH 4, 2009
CALGARY, ALBERTA, CANADA

management's assessment of internal control over financial reporting

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

Management, together with the Company's President and Chief Operating Officer 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, together with the Company's President and Chief Operating Officer and the Company's Chief Financial Officer and Senior Vice-President, Finance, has concluded that the Company's internal control over financial reporting is effective as at December 31, 2008. 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, 2008, as stated in their Auditors' Report.

Steve W. Laut
PRESIDENT & CHIEF OPERATING OFFICER

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

MARCH 4, 2009
CALGARY, ALBERTA, CANADA

independent auditors' report

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2008, 2007, and 2006 consolidated financial statements and of its internal control over financial reporting as at December 31, 2008. 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, 2008 and December 31, 2007, 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, 2008. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits of the Company's consolidated financial statements 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, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Canadian Natural Resource Limited's internal control over financial reporting as at December 31, 2008, 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 Assessment of Internal Control over Financial Reporting. 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, 2008 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
CALGARY, ALBERTA, CANADA
MARCH 4, 2009

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's consolidated financial statements, such as the changes indicated in the Consolidated Statements of Shareholders' Equity and Comprehensive Income. Our report to the shareholders dated March 4, 2009 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
CALGARY, ALBERTA, CANADA
MARCH 4, 2009

consolidated balance sheets

As at December 31 (millions of Canadian dollars)	2008	2007
ASSETS		
Current assets		
Cash and cash equivalents	**$ 27**	$ 21
Accounts receivable and other	**1,514**	1,662
Future income tax (note 8)	**–**	480
Current portion of other long-term assets (note 3)	**1,851**	18
	3,392	2,181
Property, plant and equipment (note 4)	**38,966**	33,902
Other long-term assets (note 3)	**292**	31
	$ 42,650	$ 36,114
LIABILITIES		
Current liabilities		
Accounts payable	**$ 383**	$ 379
Accrued liabilities	**1,802**	1,567
Future income tax (note 8)	**585**	–
Current portion of long-term debt (note 5)	**420**	–
Current portion of other long-term liabilities (note 6)	**230**	1,617
	3,420	3,563
Long-term debt (note 5)	**12,596**	10,940
Other long-term liabilities (note 6)	**1,124**	1,561
Future income tax (note 8)	**7,136**	6,729
	24,276	22,793
SHAREHOLDERS' EQUITY		
Share capital (note 9)	**2,768**	2,674
Retained earnings	**15,344**	10,575
Accumulated other comprehensive income (note 10)	**262**	72
	18,374	13,321
	$ 42,650	$ 36,114

Commitments and contingencies (note 14).

Approved by the Board of Directors:

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)	2008	2007	2006
Revenue	**$ 16,173**	$ 12,543	$ 11,643
Less: royalties	**(2,017)**	(1,391)	(1,245)
Revenue, net of royalties	**14,156**	11,152	10,398
Expenses			
Production	**2,451**	2,184	1,949
Transportation and blending	**1,936**	1,570	1,443
Depletion, depreciation and amortization	**2,683**	2,863	2,391
Asset retirement obligation accretion (note 6)	**71**	70	68
Administration	**180**	208	180
Stock-based compensation (recovery) expense (note 6)	**(52)**	193	139
Interest, net	**128**	276	140
Risk management activities (note 13)	**(1,230)**	1,562	312
Foreign exchange loss (gain)	**718**	(471)	122
	6,885	8,455	6,744
Earnings before taxes	**7,271**	2,697	3,654
Taxes other than income tax (note 8)	**178**	165	256
Current income tax expense (note 8)	**501**	380	222
Future income tax expense (recovery) (note 8)	**1,607**	(456)	652
Net earnings	**$ 4,985**	$ 2,608	$ 2,524
Net earnings per common share (note 12)			
Basic and diluted	**$ 9.22**	$ 4.84	$ 4.70

consolidated statements of shareholders' equity

For the years ended December 31 (millions of Canadian dollars)	2008	2007	2006
Share capital			
Balance – beginning of year	$ 2,674	$ 2,562	$ 2,442
Issued upon exercise of stock options	18	21	21
Previously recognized liability on stock options exercised for common shares	76	91	101
Purchase of common shares under Normal Course Issuer Bid	–	–	(2)
Balance – end of year	2,768	2,674	2,562
Retained earnings			
Balance – beginning of year, as originally reported	10,575	8,141	5,804
Transition adjustment on adoption of financial instruments standards	–	10	–
Balance – beginning of year, as restated	10,575	8,151	5,804
Net earnings	4,985	2,608	2,524
Dividends on common shares (note 9)	(216)	(184)	(161)
Purchase of common shares under Normal Course Issuer Bid	–	–	(26)
Balance – end of year	15,344	10,575	8,141
Accumulated other comprehensive income (loss)			
Balance – beginning of year	72	(13)	(9)
Transition adjustment on adoption of financial instruments standards	–	159	–
Balance – beginning of year, after effect of transition adjustment	72	146	(9)
Other comprehensive income (loss), net of taxes	190	(74)	(4)
Balance – end of year	262	72	(13)
Shareholders' equity	$ 18,374	$ 13,321	$ 10,690

consolidated statements of comprehensive income

For the years ended December 31 (millions of Canadian dollars)	2008	2007	2006
Net earnings	$ 4,985	$ 2,608	$ 2,524
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income during the year, net of taxes of $1 million (2007 – $6 million, 2006 – $nil)	30	38	–
Reclassification to net earnings, net of taxes of $6 million (2007 – $45 million, 2006 – $nil)	(12)	(96)	–
	18	(58)	–
Foreign currency translation adjustment			
Translation of net investment	172	(16)	(4)
Other comprehensive income (loss), net of taxes	190	(74)	(4)
Comprehensive income	$ 5,175	$ 2,534	$ 2,520

consolidated statements of cash flows

For the years ended December 31 (millions of Canadian dollars)	2008	2007	2006
Operating activities			
Net earnings	**$ 4,985**	$ 2,608	$ 2,524
Non-cash items			
Depletion, depreciation and amortization	**2,683**	2,863	2,391
Asset retirement obligation accretion	**71**	70	68
Stock-based compensation (recovery) expense	**(52)**	193	139
Unrealized risk management (gain) loss	**(3,090)**	1,400	(1,013)
Unrealized foreign exchange loss (gain)	**832**	(524)	134
Deferred petroleum revenue tax (recovery) expense	**(67)**	44	37
Future income tax expense (recovery)	**1,607**	(456)	652
Other	**25**	38	(2)
Abandonment expenditures	**(38)**	(71)	(75)
Net change in non-cash working capital (note 15)	**(189)**	(346)	(679)
	6,767	5,819	4,176
Financing activities			
(Repayment) issue of bank credit facilities, net	**(623)**	(1,925)	6,499
Issue of medium-term notes	**–**	273	400
Repayment of senior unsecured notes	**(31)**	(33)	–
Issue of US dollar debt securities	**1,215**	2,553	788
Issue of common shares on exercise of stock options	**18**	21	21
Dividends on common shares	**(208)**	(178)	(153)
Purchase of common shares	**–**	–	(28)
Net change in non-cash working capital (note 15)	**46**	8	37
	417	719	7,564
Investing activities			
Expenditures on property, plant and equipment	**(7,433)**	(6,464)	(7,266)
Net proceeds on sale of property, plant and equipment	**20**	110	71
Net expenditures on property, plant and equipment	**(7,413)**	(6,354)	(7,195)
Acquisition of Anadarko Canada Corporation (note 16)	**–**	–	(4,641)
Net change in non-cash working capital (note 15)	**235**	(186)	101
	(7,178)	(6,540)	(11,735)
Increase (decrease) in cash and cash equivalents	**6**	(2)	5
Cash and cash equivalents – beginning of year	**21**	23	18
Cash and cash equivalents – end of year	**$ 27**	$ 21	$ 23

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.

Within Western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") in a series of staged development phases ("Phases"). The Horizon Project is designed to produce synthetic crude oil through bitumen mining and upgrading operations.

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 18.

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) 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 Operations and Upgrading Operations

The Company's Horizon Project is comprised of both mining operations and upgrading operations and accordingly, capitalized costs related to the Horizon Project 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 the Horizon Project. Construction and development for a particular Phase of the Horizon Project is considered complete once the Phase is available for its intended use. Costs related to major maintenance turnaround activities will be capitalized and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround.

Midstream and Other

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

(E) OVERBURDEN REMOVAL COSTS

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

(F) CAPITALIZED INTEREST

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

(G) LEASES

Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate. 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.

(H) DEPLETION, DEPRECIATION AND AMORTIZATION

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 uses. 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 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 Operations and Upgrading Operations

Upon commencement of operations for the Horizon Project, mine-related costs and costs of the upgrader and related infrastructure located on the Horizon Project site will be amortized on the unit-of-production method based on the estimated proved reserves of the Horizon Project 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 the Horizon Project 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 the Horizon Project 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 the Horizon Project 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.

(I) 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 Project 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.

(J) 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.

(K) 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.

(L) TRANSPORTATION AND BLENDING

Transportation and blending costs incurred to transport crude oil and natural gas to customers are recorded as a separate cost 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") by the life-of-the-field method. 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 the Horizon Project. 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 unless formally designated as hedges.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial 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.

Effective January 1, 2007, 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 crude oil or natural gas 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 the foreign currency forward contracts 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

Effective January 1, 2009, the Company will adopt the following new accounting standard issued by the CICA:

Goodwill and Intangible Assets

- Section 3064 – "Goodwill and Intangible Assets" replaces 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" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard will not have a material impact on the Company's financial statements.

(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 is currently assessing which accounting policies will be affected by the change to IFRS and 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 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Company adopted the following new accounting and disclosure standards issued by the CICA:

- Section 1535 – "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affected disclosure only and did not impact the Company's accounting for capital (note 11).
- Section 3031 – "Inventories" replaces Section 3030 – "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.
- Section 3862 – "Financial Instruments – Disclosure" and Section 3863 – "Financial Instruments – Presentation" replace Section 3861 – "Financial Instruments – Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affected disclosures only and did not impact the Company's accounting for financial instruments (note 13).

3. OTHER LONG-TERM ASSETS

	2008	2007
Risk management (note 13)	**$ 2,119**	$ –
Other	**24**	49
	2,143	49
Less: current portion	**1,851**	18
	$ 292	$ 31

4. PROPERTY, PLANT AND EQUIPMENT

	2008			2007		
	Cost	**Accumulated depletion and depreciation**	**Net**	Cost	Accumulated depletion and depreciation	Net
Conventional crude oil and natural gas						
North America	**$ 36,532**	**$ 14,381**	**$ 22,151**	$ 34,195	$ 12,162	$ 22,033
North Sea	**4,167**	**2,119**	**2,048**	3,174	1,446	1,728
Offshore West Africa	**2,671**	**777**	**1,894**	1,833	645	1,188
Other	**40**	**14**	**26**	39	14	25
Horizon Project	**12,573**	**–**	**12,573**	8,651	–	8,651
Midstream	**278**	**72**	**206**	269	64	205
Head office	**190**	**122**	**68**	170	98	72
	$ 56,451	**$ 17,485**	**$ 38,966**	$ 48,331	$ 14,429	$ 33,902

During the year ended December 31, 2008, the Company capitalized directly attributable administrative costs of $55 million (2007 – $47 million, 2006 – $41 million) in the North Sea and Offshore West Africa, related to exploration and development and $404 million (2007 – $312 million, 2006 – $255 million) in North America, related to the Horizon Project construction.

During the year ended December 31, 2008, the Company capitalized $481 million (2007 – $356 million, 2006 – $196 million) in construction period interest costs related to the Horizon Project.

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

	2008	2007
Conventional crude oil and natural gas		
North America	$ 2,271	$ 2,259
North Sea	12	10
Offshore West Africa	595	138
Other	26	25
Horizon Project	12,573	8,651
	$ 15,477	$ 11,083

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, 2008:

	2009	2010	2011	2012	2013	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 53.73	$ 63.41	$ 69.53	$ 79.59	$ 92.01	2.0%
Hardisty Heavy 12° API (C$/bbl)	$ 47.05	$ 54.58	$ 59.96	$ 67.53	$ 74.08	2.0%
Edmonton Par (C$/bbl)	$ 65.35	$ 72.78	$ 79.95	$ 86.57	$ 94.97	2.0%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 51.73	$ 61.37	$ 67.45	$ 77.47	$ 89.84	2.0%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 6.30	$ 7.32	$ 7.56	$ 8.49	$ 9.74	2.0%
AECO (C$/mmbtu)	$ 6.82	$ 7.56	$ 7.84	$ 8.38	$ 9.20	2.2%
Huntingdon/Sumas (C$/mmbtu)	$ 6.82	$ 7.56	$ 7.84	$ 8.38	$ 9.20	2.2%

5. LONG-TERM DEBT

	2008	2007
Canadian dollar denominated debt		
Bank credit facilities		
Bankers' acceptances	**$ 4,073**	$ 4,696
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
	5,273	5,896
US dollar denominated debt		
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2008 – US$31 million, 2007 – US$62 million)	**38**	61
US dollar debt securities		
7.80% due July 2, 2008 (2008 – US$nil, 2007 – US$8 million)	**–**	8
6.70% due July 15, 2011 (2008 – US$400 million, 2007 – US$400 million)	**490**	395
5.45% due October 1, 2012 (2008 – US$350 million, 2007 – US$350 million)	**429**	346
5.15% due February 1, 2013 (2008 – US$400 million, 2007 – US$nil)	**490**	–
4.90% due December 1, 2014 (2008 – US$350 million, 2007 – US$350 million)	**429**	346
6.00% due August 15, 2016 (2008 – US$250 million, 2007 – US$250 million)	**306**	247
5.70% due May 15, 2017 (2008 – US$1,100 million, 2007 – US$1,100 million)	**1,346**	1,087
5.90% due February 1, 2018 (2008 – US$400 million, 2007 – US$nil)	**490**	–
7.20% due January 15, 2032 (2008 – US$400 million, 2007 – US$400 million)	**490**	395
6.45% due June 30, 2033 (2008 – US$350 million, 2007 – US$350 million)	**429**	346
5.85% due February 1, 2035 (2008 – US$350 million, 2007 – US$350 million)	**429**	346
6.50% due February 15, 2037 (2008 – US$450 million, 2007 – US$450 million)	**551**	445
6.25% due March 15, 2038 (2008 – US$1,100 million, 2006 – US$1,100 million)	**1,346**	1,087
6.75% due February 1, 2039 (2008 – US$400 million, 2007 – US$nil)	**490**	–
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	(23)
	7,730	5,086
Fair value impact of interest rate swaps on US dollar debt securities (2)	**68**	9
	7,798	5,095
Long-term debt before transaction costs	**13,071**	10,991
Less: transaction costs (1) (3)	**(55)**	(51)
	13,016	10,940
Less: current portion	**420**	–
	$ 12,596	$ 10,940

(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 $68 million (2007 – $9 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, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- 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.

During 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were also extended and now mature June 2012. Both 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 will 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.

In conjunction with the closing of the acquisition of Anadarko Canada Corporation ("ACC") in November 2006 (note 16), the Company executed a $3,850 million, non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing borrowing capacity under its other long-term bank credit facilities, which were $2,050 million at December 31, 2008, supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2008, was 2.2% (2007 – 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2008.

Medium-term Notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2007, $125 million of the 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior Unsecured Notes

The adjustable rate senior unsecured notes bear interest at 6.54%, with the final annual principal repayment of US$31 million due in May 2009. During 2008, US$31 million of the senior unsecured notes were repaid.

US Dollar Debt Securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a 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. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

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

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017, and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million (note 13). The Company also entered into a cross currency swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million (note 13). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

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 from the date of termination of the interest rate swaps for subsequent changes in fair value. 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.

During 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on US dollar denominated long-term debt are now recognized in the consolidated statements of earnings.

Required Debt Repayments

Required debt repayments are as follows:

Year	Repayment
2009	$ 2,385
2010	$ 400
2011	$ 490
2012	$ 429
2013	$ 890
Thereafter	$ 6,707

No debt repayments are reflected in the above table for $1,725 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 entire amounts due under these facilities would be due in 2012.

6. OTHER LONG-TERM LIABILITIES

	2008	2007
Asset retirement obligations	**$ 1,064**	$ 1,074
Stock-based compensation	**171**	529
Risk management (note 13)	**–**	1,474
Other	**119**	101
	1,354	3,178
Less: current portion	**230**	1,617
	$ 1,124	$ 1,561

Asset Retirement Obligations

At December 31, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $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 6.7% (2007 – 6.6%; 2006 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	2008	2007	2006
Balance – beginning of year	**$ 1,074**	$ 1,166	$ 1,112
Liabilities incurred	**18**	21	26
Liabilities acquired (note 16)	**3**	–	56
Liabilities disposed	**–**	(65)	–
Liabilities settled	**(38)**	(71)	(75)
Asset retirement obligation accretion	**71**	70	68
Revision of estimates	**(156)**	35	(21)
Foreign exchange	**92**	(82)	–
Balance – end of year	**$ 1,064**	$ 1,074	$ 1,166

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 twelve month period if all vested options are surrendered for cash settlement.

	2008	2007	2006
Balance – beginning of year	**$ 529**	$ 744	$ 891
Stock-based compensation	**(52)**	193	139
Cash payment for options surrendered	**(207)**	(375)	(264)
Transferred to common shares	**(76)**	(91)	(101)
Capitalized to Horizon Project	**(23)**	58	79
Balance – end of year	**171**	529	744
Less: current portion	**159**	390	611
	$ 12	$ 139	$ 133

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 7.0% (2007 – 5.5%) 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, 2008 was $27 million (2007 – $32 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, 2008, these plan assets had a fair value of $34 million (2007 – $47 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $9 million at December 31, 2008 (2007 – $10 million).

8. TAXES

Taxes Other Than Income Tax

	2008	2007	2006
Current PRT expense	$ 210	$ 97	$ 196
Deferred PRT (recovery) expense	(67)	44	37
Provincial capital taxes and surcharges	35	24	23
	$ 178	$ 165	$ 256

Income Tax

The provision for income tax is as follows:

	2008	2007	2006
Current income tax – North America	$ 33	$ 96	$ 143
Current income tax – North Sea	340	210	30
Current income tax – Offshore West Africa	128	74	49
Current income tax expense	501	380	222
Future income tax expense (recovery)	1,607	(456)	652
Income tax expense (recovery)	$ 2,108	$ (76)	$ 874

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:

	2008	2007	2006
Canadian statutory income tax rate	29.8%	32.5%	34.9%
Income tax provision at statutory rate	$ 2,166	$ 877	$ 1,275
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	–	–	131
Canadian resource allowance	–	–	(129)
Deductible UK petroleum revenue tax	(72)	(71)	(82)
Foreign and domestic tax rate differentials	(5)	(25)	6
North America income tax rate and other legislative changes	(19)	(864)	(438)
UK income tax rate changes	–	–	110
Côte d'Ivoire income tax rate changes	(22)	–	(67)
Non-taxable portion of foreign exchange loss (gain)	127	(96)	5
Stock options exercised in shares	6	63	35
Other	(73)	40	28
Income tax expense (recovery)	$ 2,108	$ (76)	$ 874

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

	2008	2007
Future income tax liabilities		
Property, plant and equipment	$ 6,303	$ 5,695
Timing of partnership items	1,276	1,288
Unrealized foreign exchange gain on long-term debt	13	199
Unrealized risk management activities	651	–
Other	–	55
Future income tax assets		
Asset retirement obligations	(372)	(380)
Loss carryforwards for income tax	(62)	(104)
Stock-based compensation	(38)	(125)
Unrealized risk management activities	–	(399)
Other	(7)	–
Deferred petroleum revenue tax	(43)	20
Net future income tax liability	7,721	6,249
Less: current portion of future income tax liability (asset)	585	(480)
Future income tax liability	$ 7,136	$ 6,729

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.

During 2006, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Côte d'Ivoire.

During 2003, the Canadian Federal Government enacted legislation to phase in changes to the taxation of resource income by 2007. The legislation reduced the corporate income tax rate on resource income to 21%, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. Subsequently, 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.

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

	2008		2007	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**539,729**	**$ 2,674**	537,903	$ 2,562
Issued upon exercise of stock options	**1,262**	**18**	1,826	21
Previously recognized liability on stock options exercised for common shares	**–**	**76**	–	91
Balance – end of year	**540,991**	**$ 2,768**	539,729	$ 2,674

Normal Course Issuer Bid

The Company did not renew the Normal Course Issuer Bid during 2008. During 2007 and 2008, the Company did not purchase any common shares for cancellation (2006 – 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million).

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.

In March 2009, the Board of Directors set the Company's regular quarterly dividend at $0.105 per common share (2008 – $0.10 per common share, 2007 – $0.085 per common share).

Stock Options

The Company's Option Plan provides for 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, 2008 and 2007:

	2008		2007	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	30,659	$ 47.23	34,431	$ 33.77
Granted	7,705	$ 53.38	7,502	$ 70.03
Surrendered for cash settlement	(3,702)	$ 25.60	(7,249)	$ 16.10
Exercised for common shares	(1,262)	$ 14.61	(1,826)	$ 11.71
Forfeited	(2,438)	$ 56.56	(2,199)	$ 46.46
Outstanding – end of year	30,962	$ 51.94	30,659	$ 47.23
Exercisable – end of year	8,809	$ 44.58	7,640	$ 30.00

The range of exercise prices of stock options outstanding and exercisable at December 31, 2008 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**
$11.83 – $19.99	2,909	0.51	$	16.44	1,918	$	16.13
$20.00 – $29.99	3,023	1.30	$	25.57	1,454	$	25.42
$30.00 – $39.99	865	1.66	$	33.27	397	$	33.30
$40.00 – $49.99	6,845	5.01	$	46.37	203	$	46.29
$50.00 – $59.99	5,001	2.75	$	58.06	1,860	$	57.93
$60.00 – $69.99	4,884	3.15	$	61.54	1,762	$	61.60
$70.00 – $79.99	6,526	4.20	$	70.76	1,215	$	70.67
$80.00 – $89.99	–	–	$	–	–	$	–
$90.00 – $92.50	909	5.53	$	92.50	–	$	–
	30,962	3.32	$	51.94	8,809	$	44.58

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		2008		2007
Derivative financial instruments designated as cash flow hedges	**$**	**119**	$	101
Foreign currency translation adjustment		**143**		(29)
	$	**262**	$	72

During the next twelve months, $19 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 now operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of the Offshore West African subsidiaries. This change has been applied prospectively. The impact of this change was to increase assets by $32 million, decrease liabilities by $4 million and increase accumulated other comprehensive income by $36 million.

11. CAPITAL DISCLOSURES

As required by Canadian GAAP, effective January 1, 2008, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed regulatory capital requirements, for the purposes of this disclosure, the Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived 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 near the midpoint of the target range at 41% including the impact of capital spending on the Horizon Project.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. 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.

		2008		2007
Long-term debt [(1)]	**$**	**13,016**	$	10,940
Total shareholders' equity	**$**	**18,374**	$	13,321
Debt to book capitalization		**41%**		45%

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

12. NET EARNINGS PER COMMON SHARE

(thousands of shares)	**2008**	2007	2006
Weighted average common shares outstanding – basic and diluted	**540,647**	539,336	537,339
Net earnings – basic and diluted	**$ 4,985**	$ 2,608	$ 2,524
Net earnings per common share – basic and diluted	**$ 9.22**	$ 4.84	$ 4.70

13. FINANCIAL INSTRUMENTS

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

	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**	**–**	**–**
Risk management	**–**	**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.

	2007		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 21	$ –
Accounts receivable	1,143	–	–
Accounts payable	–	–	(379)
Accrued liabilities	–	–	(1,567)
Risk management	–	(1,474)	–
Other long-term liabilities	–	–	(86)
Long-term debt	–	–	(10,940)
	$ 1,143	$ (1,453)	$ (12,972)

The carrying value of the Company's financial instruments approximates their fair value, except for fixed rate long-term debt as noted below:

	2008		2007	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed rate long-term debt (1)	**$ 8,943**	**$ 7,649**	$ 6,244	$ 6,259

(1) 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 $68 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

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)	2008 Risk management mark-to-market	2007 Risk management mark-to-market
Balance – beginning of year	**$ (1,474)**	$ 128
Retained earnings effect of adoption of financial instruments standards	**–**	14
Net cost of outstanding put options	**297**	58
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**3,090**	(1,400)
Interest expense	**60**	9
Foreign exchange	**449**	(350)
Other comprehensive income	**18**	125
Settlement of interest rate swaps	**(20)**	–
	2,420	(1,416)
Add: put premium financing obligations [1]	**(301)**	(58)
Balance – end of year	**2,119**	(1,474)
Less: current portion	**1,851**	(1,227)
	$ 268	$ (247)

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

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

	2008	2007	2006
Net realized risk management loss	**$ 1,860**	$ 162	$ 1,325
Net unrealized risk management (gain) loss	**(3,090)**	1,400	(1,013)
	$ (1,230)	$ 1,562	$ 312

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, 2008, 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 2009 – Dec 2009	25,000 bbl/d	US$70.00 – US$111.56	WTI
	Apr 2009 – Jun 2009	4,000 bbl/d	US$70.00 – US$90.00	WTI
Crude oil puts	Jan 2009 – Dec 2009	92,000 bbl/d	US$100.00	WTI

The net cost of outstanding put options of US$242 million will be settled in 2009.

	Remaining term	Volume	Weighted average price	Index
Natural gas				
Natural gas price collars [1]	Jan 2009 – Mar 2009	500,000 GJ/d	C$6.00 – C$8.63	AECO

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 – C$8.00 natural gas AECO collars for the period January to December 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, 2008.

In addition to the derivative financial instruments noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 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, 2008, 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 2009 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

(1) London Interbank Offered Rate.

All interest rate related derivative financial instruments designated as hedges at December 31, 2008 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, 2008, 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 2009 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2009 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2009 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2008 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, the Company periodically utilizes foreign currency forward contracts to manage certain foreign currency cash management requirements. At December 31, 2008, the Company had US$408 million of these contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

As required by Canadian GAAP, effective January 1, 2008, the Company must provide certain quantitative sensitivities related to its financial instruments, which are prepared on a different basis than those sensitivities currently disclosed in the Company's other continuous disclosure documents. 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, 2008, resulting from changes in the specified variable, with all other variables held constant. These sensitivities 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	$ (32)	$ –
Decrease WTI US$1.00/bbl	$ 32	$ –
Increase AECO C$0.10/mcf	$ (1)	$ –
Decrease AECO C$0.10/mcf	$ 1	$ –
Interest rate risk		
Increase interest rate 1%	$ (32)	$ (27)
Decrease interest rate 1%	$ 32	$ 33
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (35)	$ –
Decrease exchange rate by US$0.01	$ 35	$ –

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, 2008, 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, 2008, the Company had net risk management assets of $2,119 million (December 31, 2007 – $20 million) with specific counterparties related to derivative financial instruments. The Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

c) Liquidity Risk

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

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

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	$ 383	$ –	$ –	$ –
Accrued liabilities	$ 1,802	$ –	$ –	$ –
Other long-term liabilities	$ 86	$ 18	$ 1	$ –
Long-term debt (1)	$ 2,385	$ 400	$ 1,809	$ 6,707

(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 $1,725 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:

	2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124	$ 1,175
Offshore equipment operating leases	$ 175	$ 145	$ 144	$ 116	$ 117	$ 398
Offshore drilling	$ 251	$ 62	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6	$ 4,443
Office leases	$ 25	$ 29	$ 23	$ 2	$ 2	$ 1
Other	$ 321	$ 180	$ 17	$ 12	$ 8	$ 19

(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 2009 – 2013 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 construction claims related to the Horizon Project. 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.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

		2008		2007		2006
Decrease (Increase) in non-cash working capital						
Accounts receivable and other	**$**	**111**	$	334	$	(116)
Accounts payable		**(4)**		(456)		157
Accrued liabilities		**(15)**		(402)		(582)
Net change in non-cash working capital	**$**	**92**	$	(524)	$	(541)
Relating to:						
Operating activities	**$**	**(189)**	$	(346)	$	(679)
Financing activities		**46**		8		37
Investing activities		**235**		(186)		101
	$	**92**	$	(524)	$	(541)

Other cash flow information:		2008		2007		2006
Interest paid	**$**	**574**	$	556	$	262
Taxes paid	**$**	**558**	$	418	$	703

16. BUSINESS COMBINATIONS

Anadarko Canada Corporation

In November 2006, the Company completed the acquisition of all of the issued and outstanding common shares of ACC, a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of ACC's land and production base are located in Western Canada.

The acquisition was accounted for using the purchase method. Operating results from ACC have been consolidated with the results of the Company effective from November 2, 2006, the date of acquisition, and are reported in the North America segment. The allocation of the net purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

		November 2, 2006
Net purchase price:		
Net cash consideration [(1)]	$	4,641
Net purchase price allocated as follows:		
Non-cash working capital deficit assumed and other	$	(105)
Property, plant and equipment		6,249
Long-term debt		(9)
Asset retirement obligation		(56)
Future income tax		(1,438)
	$	4,641

(1) Net cash consideration was reduced by $88 million to reflect the settlement of US dollar forward contracts designated as hedges of the ACC purchase price.

17. 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 Horizon Project is a separate segment from conventional crude oil and natural gas activities as the bitumen will be recovered through mining operations. There are currently no revenues for this project and all directly related expenditures have been capitalized.

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.

	Conventional Crude Oil and Natural Gas								
	North America			North Sea			Offshore West Africa		
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Segmented revenue	**$ 13,496**	$ 10,149	$ 9,066	**$ 1,769**	$ 1,597	$ 1,616	**$ 944**	$ 776	$ 950
Less: royalties	**(1,876)**	(1,318)	(1,203)	**(4)**	(3)	(3)	**(143)**	(70)	(39)
Revenue, net of royalties	**11,620**	8,831	7,863	**1,765**	1,594	1,613	**801**	706	911
Segmented expenses									
Production	**1,881**	1,642	1,436	**457**	432	390	**102**	94	106
Transportation and blending	**1,975**	1,595	1,465	**10**	16	15	**1**	1	1
Depletion, depreciation and amortization	**2,236**	2,350	1,897	**317**	340	297	**132**	165	189
Asset retirement obligation accretion	**42**	38	35	**27**	30	31	**2**	2	2
Realized risk management activities	**1,861**	129	1,022	**(1)**	33	303	**–**	–	–
Total segmented expenses	**7,995**	5,754	5,855	**810**	851	1,036	**237**	262	298
Segmented earnings before the following	**$ 3,625**	$ 3,077	$ 2,008	**$ 955**	$ 743	$ 577	**$ 564**	$ 444	$ 613
Non-segmented expenses									
Administration									
Stock-based compensation (recovery) expense									
Interest, net									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax expense									
Future income tax expense (recovery)									
Net earnings									

Capital Expenditures

	2008			2007		
	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	**$ 2,344**	**$ (7)**	**$ 2,337**	$ 2,428	$ 52	$ 2,480
North Sea	**319**	**(127)**	**192**	439	(77)	362
Offshore West Africa	**811**	**6**	**817**	159	(11)	148
Other	**1**	**–**	**1**	1	–	1
	3,475	**(128)**	**3,347**	3,027	(36)	2,991
Horizon Project (2)	**3,912**	**10**	**3,922**	3,301	–	3,301
Midstream	**9**	**–**	**9**	6	–	6
Head office	**17**	**–**	**17**	20	–	20
	$ 7,413	**$ (118)**	**$ 7,295**	$ 6,354	$ (36)	$ 6,318

(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 the Horizon Project also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

Midstream			Inter-segment elimination and other			Total		
2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
$ 77	$ 74	$ 72	**$ (113)**	$ (53)	$ (61)	**$ 16,173**	$ 12,543	$ 11,643
–	–	–	**6**	–	–	**(2,017)**	(1,391)	(1,245)
77	74	72	**(107)**	(53)	(61)	**14,156**	11,152	10,398
25	22	23	**(14)**	(6)	(6)	**2,451**	2,184	1,949
–	–	–	**(50)**	(42)	(38)	**1,936**	1,570	1,443
8	8	8	**(10)**	–	–	**2,683**	2,863	2,391
–	–	–	**–**	–	–	**71**	70	68
–	–	–	**–**	–	–	**1,860**	162	1,325
33	30	31	**(74)**	(48)	(44)	**9,001**	6,849	7,176
$ 44	$ 44	$ 41	**$ (33)**	$ (5)	$ (17)	**5,155**	4,303	3,222
						180	208	180
						(52)	193	139
						128	276	140
						(3,090)	1,400	(1,013)
						718	(471)	122
						(2,116)	1,606	(432)
						7,271	2,697	3,654
						178	165	256
						501	380	222
						1,607	(456)	652
						$ 4,985	$ 2,608	$ 2,524

Segmented Assets

	2008	2007
Conventional crude oil and natural gas		
North America	**$ 24,875**	$ 23,617
North Sea	**2,638**	1,957
Offshore West Africa	**2,013**	1,354
Other	**64**	41
Horizon Project	**12,677**	8,740
Midstream	**315**	333
Head office	**68**	72
	$ 42,650	$ 36,114

18. 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	2008	2007	2006
Net earnings – Canadian GAAP		**$ 4,985**	$ 2,608	$ 2,524
Adjustments				
Depletion, net of taxes of $2,503 million (2007 – $1 million, 2006 – $1 million)	(A,D)	**(6,169)**	(10)	2
Stock-based compensation, net of taxes of $32 million (2007 – $3 million, 2006 – $18 million)	(B)	**(76)**	(22)	(40)
Future income taxes	(G)	**234**	(234)	–
Derivative financial instruments and hedging activities, net of taxes of $nil (2007 – $nil, 2006 – $15 million)	(C,D)	**–**	–	117
Net earnings (loss) before cumulative effect of change in accounting policy – US GAAP		**(1,026)**	2,342	2,603
Cumulative effect of change in accounting policy, net of taxes of $nil (2007 – $nil, 2006 – $3 million)	(B)	**–**	–	(8)
Net earnings (loss) – US GAAP		**$ (1,026)**	$ 2,342	$ 2,595
Net earnings (loss) before cumulative effect of change in accounting policy – US GAAP per common share				
Basic		**$ (1.90)**	$ 4.34	$ 4.84
Diluted	(F)	**$ (1.90)**	$ 4.32	$ 4.77
Net earnings (loss) – US GAAP per common share				
Basic		**$ (1.90)**	$ 4.34	$ 4.83
Diluted	(F)	**$ (1.90)**	$ 4.32	$ 4.75

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

(millions of Canadian dollars)	Notes	2008	2007	2006
Comprehensive income – Canadian GAAP		**$ 5,175**	$ 2,534	$ 2,520
US GAAP earnings adjustments		**(6,011)**	(266)	71
Derivative financial instruments and hedging activities, net of taxes of $nil (2007 – $nil million; 2006 – $394 million)	(C)	**–**	–	805
Comprehensive income (loss) – US GAAP		**$ (836)**	$ 2,268	$ 3,396

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

		2008		
(millions of Canadian dollars)	Notes	**Canadian GAAP**	**Increase (Decrease)**	**US GAAP**
Current assets		**$ 3,392**	**$ –**	**$ 3,392**
Property, plant and equipment	(A,B,D,E)	**38,966**	**(8,551)**	**30,415**
Other long-term assets	(H)	**292**	**55**	**347**
		$ 42,650	**$ (8,496)**	**$ 34,154**
Current liabilities	(B)	**$ 3,420**	**$ 150**	**$ 3,570**
Long-term debt	(H)	**12,596**	**55**	**12,651**
Other long-term liabilities	(B)	**1,124**	**15**	**1,139**
Future income tax	(A,B,D,E,G)	**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**

(millions of Canadian dollars)	Notes	2007 Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$ 2,181	$ –	$ 2,181
Property, plant and equipment	(A,B,D,E)	33,902	91	33,993
Other long-term assets	(H)	31	51	82
		$ 36,114	$ 142	$ 36,256
Current liabilities	(B)	$ 3,563	$ 66	$ 3,629
Long-term debt	(H)	10,940	51	10,991
Other long-term liabilities	(B)	1,561	20	1,581
Future income tax	(A,B,D,E,G)	6,729	236	6,965
Share capital		2,674	–	2,674
Retained earnings		10,575	(231)	10,344
Accumulated other comprehensive income		72	–	72
		$ 36,114	$ 142	$ 36,256

Notes:

(A) Under Canadian full cost accounting rules, costs capitalized in each country cost centre are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(H). 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 and costs as at the balance sheet date ("constant dollar pricing") 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 to current and prior years resulted in the recognition of ceiling test impairments under US GAAP, which reduced property, plant and equipment by $8,697 million in 2008 (2007 – $36 million, 2006 – $40 million).

For the year ended December 31, 2008, US GAAP net earnings would have decreased by $6,164 million, net of income taxes of $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 $3 million (2007 – decreased by $4 million, 2006 – increased by $3 million), net of income taxes of $1 million (2007 – $8 million, 2006 – $2 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.

(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 ("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, 2008, US GAAP net earnings would have decreased by $76 million (2007 – $22 million, 2006 – $48 million), net of income taxes of $32 million (2007 – $3 million, 2006 – $21 million including the cumulative effect of the change in accounting policy of $8 million, net of income taxes of $3 million). The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(C) Effective January 1, 2007, the Company adopted new accounting standards for financial instruments. The Company's accounting policies for financial instruments under Canadian GAAP are described in notes 1(Q) and 1(R). After adopting the new standards, Canadian GAAP is substantially harmonized with US GAAP as prescribed by FAS 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149.

Prior to adoption of the new accounting policies, the net earnings associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the year ended December 31, 2006 would have been $29 million, net of income taxes of $15 million. Comprehensive income would have increased by $805 million as a result of recording all derivative financial instruments at fair value in accordance with US GAAP.

(D) During 2006, under Canadian GAAP, the Company hedged the foreign currency component of the US dollar purchase price of ACC using derivative financial instruments formally designated as cash flow hedges. Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging, and therefore, for the year ended December 31, 2006, the $88 million after-tax gain on the derivative financial instruments would have been included in net earnings. For the year ended December 31, 2008, US GAAP net earnings would have been decreased by $8 million (2007 – $6 million, 2006 – $1 million), net of income taxes of $3 million (2007 – $7 million, 2006 – $1 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.

(E) 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.

(F) 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 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, 2008, no additional shares would have been included in the calculation of diluted earnings per share for US GAAP as the impact would have been anti-dilutive (2007 – 3,376,000 additional shares, 2006 – 8,762,000 additional shares).

(G) 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 year ended December 31, 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.

(H) Effective January 1, 2007, 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 $55 million of debt issue costs from long-term debt to deferred charges in 2008 (2007 – $51 million). There was no difference from Canadian GAAP prior to 2007.

(I) In September 2006, the FASB issued FAS 157 "Fair Value Measurements" effective for fiscal years beginning after November 15, 2007. The implementation date was subsequently delayed until years beginning on or after November 15, 2008 except for non financial assets and non financial liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FAS 157 standardizes the meaning of "Fair Value" in all FASB statements that refer to fair value and expands disclosures about fair value measurements. The adoption of this standard did not result in a Canadian and US GAAP reconciling item.

(J) In February 2007, the FASB issued FAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" effective for fiscal years beginning after November 15, 2007. FAS 159 allows entities to carry most financial instruments at fair value, even if existing standards would not require this. The adoption of this standard did not result in a US GAAP reconciling item.

(K) In December 2007, the FASB issued FAS 141(R) "Business Combinations", which replaces FAS 141 effective for fiscal years beginning after December 15, 2008. FAS 141(R) 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.

(L) US GAAP – Recently issued accounting standards

During 2008, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and 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" price. These revisions will impact the reserves used in the Company's accounting for depletion and its calculation of the ceiling test under US GAAP. These revisions are effective for filings made on or after January 1, 2010, and will be applied prospectively with no retroactive restatement.

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 Statement 69 ("FAS 69"), "Disclosures about Oil and Gas Producing Activities", 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, 2008, the reports by Sproule Associates Limited ("Sproule") covered 100% of the Company's conventional reserves.
- For the years ended December 31, 2007, 2006, and 2005 the reports by Sproule and Ryder Scott Company covered 100% of the Company's conventional reserves.

Proved crude oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGLs") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

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 conventional crude oil and natural gas reserves, net of royalties, as at December 31, 2008, 2007, 2006, and 2005:

Crude oil and NGLs (mmbbl)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net proved reserves				
Reserves, December 31, 2005	694	290	134	1,118
Extensions and discoveries	53	3	–	56
Improved recovery	190	26	–	216
Purchases of reserves in place	26	–	–	26
Sales of reserves in place	–	–	–	–
Production	(75)	(22)	(13)	(110)
Revisions of prior estimates (1)	(1)	2	9	10
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 (1)	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	**948**	**256**	**142**	**1,346**
Net proved developed reserves				
December 31, 2005	402	214	80	696
December 31, 2006	420	214	63	697
December 31, 2007	426	240	70	736
December 31, 2008	**428**	**97**	**107**	**632**

(1) Revisions of prior estimates for the years ended December 31, 2007 and 2006 include the impact of economic revisions due to prices.

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2005	2,741	29	72	2,842
Extensions and discoveries	250	–	–	250
Improved recovery	74	–	–	74
Purchases of reserves in place	1,111	–	–	1,111
Sales of reserves in place	(1)	–	–	(1)
Production	(433)	(5)	(3)	(441)
Revisions of prior estimates [1]	(37)	13	(13)	(37)
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**
Net proved developed reserves				
December 31, 2005	2,300	16	10	2,326
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**

(1) Revisions of prior estimates for the years ended December 31, 2007 and 2006 include the impact of economic revisions due to prices.

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

			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**

			2007		
(millions of Canadian dollars)	North America	North Sea	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

			2006		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 29,596	$ 3,346	$ 1,601	$ 14	$ 34,557
Unproved properties	2,244	24	84	24	2,376
	31,840	3,370	1,685	38	36,933
Less: accumulated depletion and depreciation	(9,878)	(1,341)	(481)	(14)	(11,714)
Net capitalized costs	$ 21,962	$ 2,029	$ 1,204	$ 24	$ 25,219

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

	2008				
(millions of Canadian dollars)	**North America**	**North Sea**	**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**

	2007				
(millions of Canadian dollars)	North America	North Sea	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

	2006				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 5,627	$ –	$ 1	$ –	$ 5,628
Unproved	910	–	–	–	910
Exploration	238	4	1	11	254
Development	2,807	628	133	–	3,568
Costs incurred	$ 9,582	$ 632	$ 135	$ 11	$ 10,360

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, 2008, 2007, and 2006 are summarized in the following tables:

	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

(millions of Canadian dollars)		2006 North America		North Sea		Offshore West Africa		Total
Crude oil and natural gas revenue, net of royalties and blending costs	$	5,707	$	1,310	$	911	$	7,928
Production		(1,436)		(390)		(106)		(1,932)
Transportation		(326)		(15)		(1)		(342)
Depletion, depreciation and amortization		(1,894)		(297)		(189)		(2,380)
Asset retirement obligation accretion		(35)		(31)		(2)		(68)
Petroleum revenue tax		–		(234)		–		(234)
Income tax		(706)		(172)		(172)		(1,050)
Results of operations	$	1,310	$	171	$	441	$	1,922

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 year-end sales prices and costs 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 year-end sales prices and costs 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 FAS 69:

(millions of Canadian dollars)		**2008 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)		2007 North America		North Sea		Offshore West Africa		Total
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

(millions of Canadian dollars)	2006 North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 63,368	$ 20,815	$ 7,779	$ 91,962
Future production costs	(21,634)	(8,077)	(2,517)	(32,228)
Future development and asset retirement obligations	(7,029)	(4,348)	(824)	(12,201)
Future income taxes	(9,118)	(5,623)	(1,372)	(16,113)
Future net cash flows	25,587	2,767	3,066	31,420
10% annual discount for timing of future cash flows	(11,214)	(956)	(1,258)	(13,428)
Standardized measure of future net cash flows	$ 14,373	$ 1,811	$ 1,808	$ 17,992

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)	**2008**	2007	2006
Sales of crude oil and natural gas produced, net of production costs	**$ (9,679)**	$ (7,150)	$ (5,635)
Net changes in sales prices and production costs	**(14,680)**	7,412	(2,420)
Extensions, discoveries and improved recovery	**820**	1,429	4,769
Changes in estimated future development costs	**(715)**	(169)	(1,885)
Purchases of proved reserves in place	**113**	39	2,406
Sales of proved reserves in place	**(1)**	(103)	(2)
Revisions of previous reserve estimates	**112**	2,380	81
Accretion of discount	**3,468**	2,760	3,112
Changes in production timing and other	**767**	508	(2,156)
Net change in income taxes	**8,462**	(3,378)	1,270
Net change	**(11,333)**	3,728	(460)
Balance – beginning of year	**21,720**	17,992	18,452
Balance – end of year	**$ 10,387**	$ 21,720	$ 17,992

ten-year review

Years ended December 31	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
FINANCIAL INFORMATION (1)										
(C$ millions, except per share amounts)										
Net earnings	**4,985**	2,608	2,524	1,050	1,405	1,403	539	639	758	213
Per share - basic	**$ 9.22**	$ 4.84	$ 4.70	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$ 0.51
Cash flow from operations (2)	**6,969**	6,198	4,932	5,021	3,769	3,160	2,254	1,920	1,884	724
Per share - basic	**$ 12.89**	$ 11.49	$ 9.18	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$ 1.74
Capital expenditures, net of dispositions (including business combinations)	**7,451**	6,425	12,025	4,932	4,633	2,506	4,069	1,885	2,823	1,901
Balance sheet information										
Working capital (deficiency) surplus	**(28)**	(1,382)	(832)	(1,774)	(652)	(505)	(14)	(6)	(77)	36
Property, plant and equipment, net	**38,966**	33,902	30,767	19,694	17,064	13,714	12,934	8,766	7,439	4,679
Total assets	**42,650**	36,114	33,160	21,852	18,372	14,643	13,793	9,290	8,051	4,976
Long-term debt	**12,596**	10,940	11,043	3,321	3,538	2,748	4,200	2,788	2,573	2,157
Shareholders' equity	**18,374**	13,321	10,690	8,237	7,324	6,006	4,754	3,928	3,297	1,962
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**540,991**	539,729	537,903	536,348	536,361	534,926	535,104	484,804	489,116	445,816
Weighted average shares outstanding (thousands)	**540,647**	539,336	537,339	536,650	536,223	536,940	511,532	485,200	466,804	415,624
Dividends declared per common share	**$ 0.40**	$ 0.34	$ 0.30	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ –	$ –
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**679,738**	429,034	508,935	637,992	606,024	590,702	619,316	534,976	567,412	430,460
Share Price ($/share)										
High	**$ 111.30**	$ 80.02	$ 73.91	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$ 9.65
Low	**$ 34.19**	$ 52.45	$ 45.49	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$ 4.95
Close	**$ 48.75**	$ 72.58	$ 62.15	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$ 8.81
NYSE – US$										
Trading volume (thousands)	**967,228**	486,266	401,909	251,554	125,468	46,916	31,864	20,764	3,172	–
Share Price ($/share)										
High	**$ 109.32**	$ 87.17	$ 64.38	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$ –
Low	**$ 26.43**	$ 44.56	$ 40.29	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$ –
Close	**$ 39.98**	$ 73.14	$ 53.23	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$ –
RATIOS										
Debt to book capitalization (3)	**41%**	45%	51%	29%	34%	33%	47%	42%	44%	52%
Return on average common shareholders' equity, after tax (3)	**33%**	22%	27%	14%	21%	26%	13%	18%	29%	13%
Daily production before royalties per ten thousand common shares (boe/d)	**10.4**	11.3	10.8	10.3	9.6	8.5	8.2	7.4	6.6	5.0
Conventional proved and probable reserves per common share (boe) (4)	**6.1**	6.3	6.4	4.8	4.3	4.0	3.3	3.1	2.9	2.4
Net asset value per common share (1) (5)	**$ 79.78**	$ 68.93	$ 56.41	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54	$ 12.33

(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 constant dollar Company gross reserves (before royalties), using year-end common shares outstanding.
(5) Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's AIF for conventional reserves, with $250/acre added for core undeveloped land in 2005, 2006, 2007 and 2008, $75/acre for all years prior, less long-term debt and adjustments for working capital. Refer to the "Year-End Reserves" section of the Annual Report.

Years ended December 31	**2008**	2007	2006	2005	2004	2003	2002	2001	2000	1999
OPERATING INFORMATION										
Conventional crude oil and NGLs (mmbbl, constant prices and costs)										
Company gross proved reserves (before royalties)										
North America	**1,057**	1,084	1,043	785	695	672	665	644	643	554
North Sea	**256**	311	299	290	303	222	203	83	102	–
Offshore West Africa	**157**	148	145	148	125	106	94	61	36	–
	1,470	1,543	1,487	1,223	1,123	1,000	962	788	781	554
Company gross proved and probable reserves (before royalties)										
North America	**1,760**	1,806	1,753	1,154	992	977	742	740	731	640
North Sea	**399**	406	421	417	415	317	277	106	134	–
Offshore West Africa	**212**	218	223	230	214	187	162	111	46	–
	2,371	2,430	2,397	1,801	1,621	1,481	1,181	957	911	640
Conventional Natural gas (bcf, constant prices and costs)										
Company gross proved reserves (before royalties)										
North America	**4,077**	4,275	4,507	3,378	3,202	3,006	3,048	2,566	2,360	2,183
North Sea	**67**	81	37	29	27	62	71	94	91	–
Offshore West Africa	**107**	79	69	83	81	86	90	69	65	–
	4,251	4,435	4,613	3,490	3,310	3,154	3,209	2,729	2,516	2,183
Company gross proved and probable reserves (before royalties)										
North America	**5,339**	5,582	5,898	4,372	4,100	3,611	3,450	2,915	2,762	2,547
North Sea	**94**	113	93	69	57	101	89	118	114	–
Offshore West Africa	**151**	109	121	127	102	111	120	96	84	–
	5,584	5,804	6,112	4,568	4,259	3,823	3,659	3,129	2,960	2,547
Total proved reserves (before royalties) (mmboe)										
	2,178	2,282	2,256	1,804	1,674	1,526	1,497	1,243	1,200	918
Total proved and probable reserves (before royalties) (mmboe)										
	3,302	3,397	3,416	2,562	2,330	2,118	1,791	1,479	1,404	1,065
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America	**244**	247	235	222	206	175	169	167	155	87
North Sea	**45**	56	60	68	65	57	39	36	17	–
Offshore West Africa	**27**	28	37	23	12	10	7	3	2	–
	316	331	332	313	283	242	215	206	174	87
Natural gas (mmcf/d)										
North America	**1,472**	1,643	1,468	1,416	1,330	1,245	1,204	906	793	721
North Sea	**10**	13	15	19	50	46	27	12	1	–
Offshore West Africa	**13**	12	9	4	8	8	1	–	–	–
	1,495	1,668	1,492	1,439	1,388	1,299	1,232	918	794	721
Total production (before royalties) (mboe/d)										
	565	609	581	553	514	459	421	359	306	207
Product Pricing										
Average crude oil and NGLs price ($/bbl)										
	82.41	55.45	53.65	46.86	37.99	32.66	31.22	23.45	31.89	22.26
Average natural gas price ($/mcf)										
	8.39	6.85	6.72	8.57	6.50	6.21	3.77	5.45	4.92	2.52

corporate information

BOARD OF DIRECTORS

***Catherine M. Best** (1 – Chair) (2)
Interim Chief Financial Officer,
Alberta Health Services
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)
Senior Partner, McKenna Long & Aldridge LLP
Atlanta, Georgia

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

Steve W. Laut
President & Chief Operating Officer,
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. (5)
Chairman of the Board,
Canadian Natural Resources Limited
Calgary, Alberta

***Norman F. McIntyre** (2) (4) (5)
Independent Businessman
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 and Partner,
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

***Eldon R. Smith,** M.D. (2) (5 – Chair)
Professor Emeritus and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

***David A. Tuer** (1) (3) (4 – Chair)
Vice-Chairman and 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 & 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, Oil Sands

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

Tim S. McKay
Senior Vice-President, Operations

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

Terry J. Jocksch
Vice-President, International and Managing Director
CNR International (U.K.) Limited

(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.

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 and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a 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 2008 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting.

CORPORATE OFFICES

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REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

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.

	2008	2007	2006
Cash dividends declared per common share	$ 0.40	$ 0.34	$ 0.30

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of the Shareholders will be held on Thursday, May 7, 2009 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

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Canadian Natural

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