


Canadian Natural

Annual Report 2007

The Premium Value, Defined Growth, Independent




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

ACC	Anadarko Canada Corporation
AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	Specific gravity measured in degrees on the American Petroleum Institute scale
bbl	barrel
bbl/d	barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
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	Liquified 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	Securities and Exchange Commission
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
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 39 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 wellhead. Methodologies for determining annual reserves are described on pages 34 to 38. This report also includes references to financial measures commonly used in the oil and gas industry that are not defined by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore referred to as non-GAAP measures. The Company uses these non-GAAP measures to evaluate its performance, however they should not be considered an alternative to or more meaningful than net earnings.

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, restated for the two-for-one subdivision of the common shares that occurred in May 2005, shows the aggregate amount of the cash dividends declared per common share in each of its last three years ended December 31.

	2007	2006	2005
Cash dividends declared per common share	**$ 0.34**	$ 0.30	$ 0.236

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of Shareholders will be held on Thursday, May 8, 2008 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

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

diverse asset base
disciplined growth
strong leadership

We have confidence in the strength of our Assets, our Plan and our People, knowing that we continue to build upon a foundation for success for years to come.

2007 was another solid year of value creation reflecting a strong, well-balanced asset base. The Company continues to demonstrate discipline in a challenging environment.

Primrose East

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, is anticipated to add approximately 40,000 bbl/d of crude oil production. Primrose East is the second phase of the 300,000 bbl/d conventional expansion plan developed to unlock value from Canadian Natural's thermal crude oil resource base.

- Drilling and construction are currently underway. Steaming of wells is targeted for Q4/08, and production is targeted to begin in 2009.
- The expansion is anticipated to add approximately 40,000 bbl/d of increased crude oil production capacity.

Horizon Oil Sands Project

Canadian Natural has a 100% working interest in the Horizon Project, located 70 kilometers north of Fort McMurray, and is comprised of leases covering 115,000 acres. Drilling on the leases indicates an estimated 16 billion barrels of bitumen in place, with approximately 6 billion barrels of recoverable reserves and contingent resources using existing mining technologies. Phase 1 of the Horizon Project was 90% complete at the end of 2007.

- Phase 1 of the Horizon Project's first oil is expected in Q3/2008.
- The first phase of the project has the capacity to produce 110,000 bbl/d of 34° API SCO.

Four major development projects – totalling 180,000 bbl/d of additional capacity – will impact 2008 and beyond, adding significant shareholder value for years to come.

Baobab

The Baobab Project located on Block CI-40 offshore Côte d'Ivoire began in late 2003 with first oil achieved in August 2005. The project, in which the Company has a 58% working interest, initially produced approximately 30,000 bbl/d net to Canadian Natural. Subsequent issues with the control of sand and solids production led to five of ten production wells being shut in during 2006. This resulted in approximately 15,500 bbl/d of reduced net production capacity.

- A deepwater drilling rig is targeted for mobilization in mid-year 2008 for restoration of a portion of shut-in production.
- Three of the five shut-in wells are expected to be repaired during 2008 and 2009 restoring 6,000 to 10,000 bbl/d of crude oil production.

Olowi

In late 2005, the Company acquired a 90% operating interest in the production sharing agreement for the Block containing the Olowi Field, located approximately 20 kilometers off the Gabonese coast and in 30 meters water depth. A development plan, comprised of a FPSO and four drilling towers will target the western flank of the structure, where the oil is located as a rim below a large gas cap. Construction is underway and first oil is targeted for late 2008.

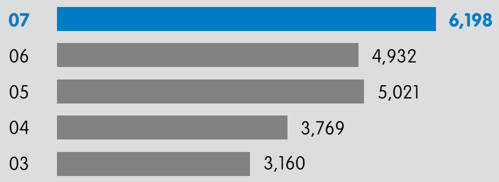
- First oil is targeted in Q4/08.
- Production is anticipated to increase during 2009 to a plateau rate of 20,000 bbl/d.

Highlights

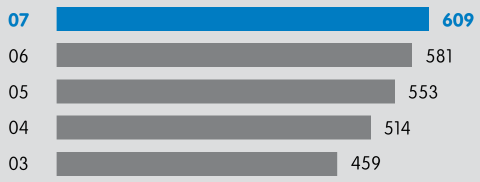
	2007		2006		2005
FINANCIAL ($ millions, except per share data)					
Revenue, before royalties	$ 12,543	$	11,643	$	11,130
Net earnings	$ 2,608	$	2,524	$	1,050
Per common share – basic	$ 4.84	$	4.70	$	1.96
– diluted	$ 4.84	$	4.70	$	1.95
Adjusted net earnings from operations (1)	$ 2,406	$	1,664	$	2,034
Per common share – basic	$ 4.46	$	3.10	$	3.79
– diluted	$ 4.46	$	3.10	$	3.78
Cash flow from operations (1)	$ 6,198	$	4,932	$	5,021
Per common share – basic	$ 11.49	$	9.18	$	9.36
– diluted	$ 11.49	$	9.18	$	9.33
Capital expenditures, net of dispositions	$ 6,425	$	12,025	$	4,932
Long-term debt	$ 10,940	$	11,043	$	3,321
Shareholders' equity	$ 13,321	$	10,690	$	8,237
OPERATING					
Daily production, before royalties					
Crude oil and NGLs (mbbl/d)					
North America	247		235		222
North Sea	56		60		68
Offshore West Africa	28		37		23
	331		332		313
Natural gas (mmcf/d)					
North America	1,643		1,468		1,416
North Sea	13		15		19
Offshore West Africa	12		9		4
	1,668		1,492		1,439
Barrels of oil equivalent (mboe/d)	609		581		553

(1) Adjusted net earnings from operations and cash flow from operations are non-GAAP measures that represent net earnings adjusted for certain non-operational and non-cash items. The Company evaluates its performance based on these measures. Adjusted net earnings from operations and cash flow from operations may not be comparable to similar measures presented by other companies.

Cash flow from operations
(C$ millions)



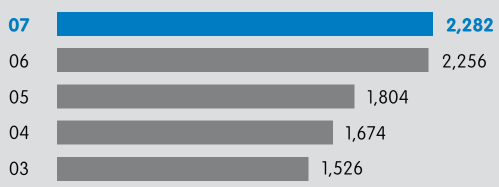
Total production, before royalties
(mboe/d)



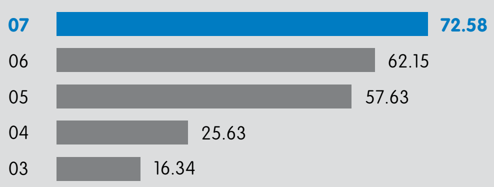
	2007	2006	2005
Drilling activity [1]			
North America	**1,060**	1,351	1,617
North Sea	**4**	8	13
Offshore West Africa	**4**	4	4
	1,068	1,363	1,634
Core undeveloped landholdings (thousands of net acres)			
North America	**12,160**	12,785	10,947
North Sea	**287**	299	352
Offshore West Africa	**206**	207	426
	12,653	13,291	11,725
Company gross proved reserves [2] (before royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**1,084**	1,043	785
North Sea	**311**	299	290
Offshore West Africa	**148**	145	148
	1,543	1,487	1,223
Conventional natural gas (bcf)			
North America	**4,275**	4,507	3,378
North Sea	**81**	37	29
Offshore West Africa	**79**	69	83
	4,435	4,613	3,490
Barrels of oil equivalent (mmboe)	**2,282**	2,256	1,804
Net proved reserves [2] (after royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**920**	887	694
North Sea	**310**	299	290
Offshore West Africa	**128**	130	134
	1,358	1,316	1,118
Conventional natural gas (bcf)			
North America	**3,521**	3,705	2,741
North Sea	**81**	37	29
Offshore West Africa	**64**	56	72
	3,666	3,798	2,842
Barrels of oil equivalent (mmboe)	**1,969**	1,949	1,592
Net oil sands proved mineable reserves [2] (after royalties)			
Bitumen (mmbbl)	**1,995**	1,853	1,848
Synthetic crude oil [3] (mmbbl)	**1,761**	1,596	1,626

(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 reserves. The reserves shown for bitumen and SCO are not additive.

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



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



Letter to Shareholders

Canadian Natural has a world class asset base that includes crude oil and natural gas conventional operations in domestic and international basins, along with our oil sands mining project. We have the Assets, Plan and People to continue to deliver shareholder value for years to come.

For Canadian Natural, 2007 was a year defined by value creation. We reached several significant achievements throughout the year, and have positioned ourselves to continue to create value for our shareholders in the near, mid and long term. We achieved a major milestone with the Horizon Project reaching 90% completion at the end of 2007 and look forward to 2008 with first oil targeted for the third quarter of this year. Our conventional crude oil and natural gas business increased production on a boe basis by 5% and we continue to leverage the strength of our assets. During the year, we faced some challenges, but as always, with challenge comes opportunity. And as we look towards 2008, we have confidence in the strength of our assets, our strategy and our people, knowing that we continue to build upon a foundation for success for the years to come.

Allan P. Markin
CHAIRMAN OF THE BOARD

N. Murray Edwards
VICE-CHAIRMAN OF THE BOARD

In a business environment characterized by high crude oil prices, lower natural gas prices, a strong Canadian dollar and uncertainty surrounding Alberta's royalties in 2009 and beyond, Canadian Natural was able to respond to the ever-changing economics of exploration and production. Our ability to efficiently allocate capital for maximum benefit, which during 2007 favoured heavy crude oil projects, underlies our fundamental approach to creating and maintaining value.

STRATEGIES AND THE BUSINESS ENVIRONMENT

During 2007, crude oil prices remained strong with natural gas prices relatively weak. We saw natural gas prices continuously decline throughout the year as a result of increased LNG imports and mild weather patterns resulting in higher storage levels. Contrary to natural gas prices, we saw crude oil prices strengthen, impacted by higher level of political risk, stronger international demand and a weaker US dollar.

For our western Canadian natural gas business in 2007, cost increases which at one time would have been manageable, became disproportionately high compared to the price of natural gas. We responded by optimizing our capital allocation process, allocating funds to capital projects with the highest return – a function of our flexibility and strength of our asset base in both crude oil and natural gas. We significantly cut natural gas spending and shifted capital into heavy crude oil drilling. We were not the only company to cut their natural gas drilling budget within the WCSB, and as a result of this industry-wide trend, natural gas development costs have decreased and we have seen increased efficiencies from our service providers. The newest challenge for natural gas comes in the form of a proposed increased royalty burden from the Alberta government. The proposed new royalty program will place increased challenges on the natural gas industry to generate reasonable economic returns. In 2008, we continue to cut back on our natural gas drilling program.

Canadian Natural controls an extensive asset base of heavy crude oil properties. As part of our heavy crude oil marketing plan, we seek to expand available markets through a combination of product blending, expansion of pipeline systems to new geographic regions, and the encouragement of new conversion capacity. As the market for Canadian heavy crude oil expands, Canadian Natural's heavy crude oil discount to light crude oil migrated towards the higher priced Mayan heavy benchmark crude. We have seen increased demand from the US Gulf Coast as political uncertainty in the refiners supply and the sharp decline in Mexican production has resulted in US Gulf Coast refiners seeking new, more stable sources of supplies of crude oil. The combination of a push from producers and pull from refiners encourages and motivates increased pipeline capacity to the US Gulf Coast.

While we experienced heavy crude oil differentials of 45% of the WTI benchmark price exiting 2007, we saw differentials during the first nine months of 2007 average 29%. Reduced differentials combined with a more controllable cost environment in heavy oil development resulted in exceptionally strong economics and marked emphasis on this type of activity in 2007. For 2008, we will continue to see increased levels of drilling in heavy crude oil.

The strength of Canadian Natural's strategy was demonstrated in 2007 by allocating capital to maximize returns. There are several fundamental elements within this strategy that allows us to focus on creating value. These are:

- Maintaining a large project portfolio in every basin we operate in, enabling us to continually high-grade current developments;
- Maintaining balance in our product mix, project time horizons and financing strategies;
- Continually balancing between acquisitions and exploration opportunities while remaining focused on low cost exploitation;
- Identifying and completing opportunistic major acquisitions; and
- Controlling costs through area knowledge and domination of core areas.

NORTH AMERICAN NATURAL GAS
Maintaining Discipline/Capturing Opportunity

We are a significant producer of natural gas in Canada, representing approximately 10% of western Canadian output. Our undeveloped land base represents the second largest portfolio in the WCSB and we have exposure to virtually every play type found in the basin. We dominate the infrastructure in our core areas allowing us to control our costs. Natural gas remains our largest single product offering, representing 45% of our production mix in 2007, compared to 42% in 2006.

The economics of natural gas drilling remain a challenge, though the burden was eased somewhat by lower natural gas drilling costs in the service sector. As near term returns for heavy oil projects remain more attractive than natural gas, we have decreased our natural gas drilling program going forward. In the meantime, we have built a drilling inventory of high quality, high-graded prospects that are ready to be drilled should the relative economics of natural gas drilling compared to crude oil normalize.

For 2008, most of the opportunities will be captured on shallow gas and CBM projects. The deeper, higher productivity wells have been most adversely affected by the proposed Alberta royalty changes, and as a result will not be a significant part of our 2008 drilling program.

Canadian Natural's natural gas assets are strong and diverse. We have the ability to grow production when the relative economics improve as compared to crude oil, leading to a more conducive environment for natural gas drilling.

John G. Langille
VICE-CHAIRMAN OF THE BOARD

NORTH AMERICAN CRUDE OIL
Disciplined Use of Technology to Create Value

Success in our Canadian crude oil operations continued in 2007 as we saw heavy crude oil pricing reach record levels during the year. We remain the leading producer of heavy crude oil in Canada and with vast amounts of original oil in place identified on our lands, we are in a enviable position to continue to grow this production.

At Pelican Lake, our waterflood and polymer flood EOR schemes are adding significant low cost reserves. We believe that the polymer flood EOR is the optimal solution for the majority of the reservoir. In 2008, we are actively rolling out the polymer flood on a commercial basis, converting 73 producing wells into polymer injection wells.

We have procured the services of two fully dedicated slant drilling rigs to complete our conventional heavy crude oil programs over the next three years. By committing to this service for an extended term we can better control efficiencies and ensure that highly trained crews are available to us to effectively develop our significant conventional heavy crude oil assets.

At our thermal in-situ projects, Primrose North continues to perform to our expectations with production of 64,000 bbl/d in 2007. Future developments are underway with the 40,000 bbl/d Primrose East Expansion targeted for first oil in 2009 and plans for the 45,000 bbl/d Kirby in-situ development, targeted for a 2011 – 2012 timeframe.

Steve W. Laut
PRESIDENT & CHIEF OPERATING OFFICER

In all, we have identified ten separate increments of in-situ developments which will unlock the tremendous value of these assets.

INTERNATIONAL OPERATIONS
Disciplined Management of Costs Drive Cash Flow

As part of our core operations, our International division faced many challenges in 2007. Looking forward, 2008 remains promising with emphasis placed on our Offshore West Africa assets. The re-entry of the wells in the Baobab Field in offshore Côte d'Ivoire, and the development of the Olowi project located in offshore Gabon represent the two major developments for our Offshore West Africa operations. First oil at Olowi is targeted for late 2008, with anticipated production expected to peak at 20,000 bbl/d in 2009.

In the North Sea, the plan continues to balance investment with value in both the short and long term, and deliver significant free cash flow by improving operating efficiencies in a mature basin. We continue to execute our strategy through exploitation beyond the optimization of existing facilities and waterfloods into more near pool developments. This maximizes utilization of the common facilities and ultimately extends economic lives of all the Fields.

HORIZON OIL SANDS PROJECT
Disciplined Execution of our Project Strategy

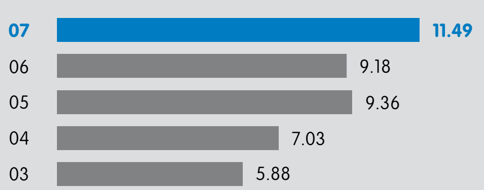
Phase 1 of Canadian Natural's Horizon Project, a bitumen mining and integrated upgrader project, made significant progress during the year. We entered 2007 at 57% complete and exited 90% complete – major progress on a mega-project. The progress we made throughout 2007 was achieved through our disciplined approach in which significant front end engineering efforts afforded us the ability to obtain the majority of the Phase 1 construction costs under lump sum bids. Overall, project certainty was augmented by a sound hedging program that ensured that Canadian Natural would have adequate free cash flow available to complete the four year construction effort.

Our emphasis on front end planning has provided Canadian Natural with a strong understanding of both what we are building and just as importantly, how we are going to build it. We have forged relationships with a variety of contractors from around the world and together have provided a strong definition of the construction execution plan. We have developed a unique and creative labour strategy that has enabled workers of all labour affiliations from across Canada to participate in the construction effort as equals. This strategy is facilitated through fly in and fly out capability from our on-site air strip. Today, workers from all across Canada regularly fly in and out on one of the 35 flights per week, direct to our site and home again, on various shifts which accommodate their lifestyles.

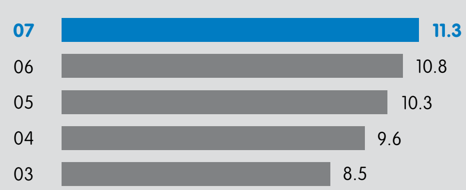
The Horizon Project is targeted to achieve first oil in the third quarter of 2008. Our teams have performed very well in the face of numerous challenges and inflationary pressures, which highlights the unique Canadian Natural focus on project execution. As a result of our commitment to "doing it right," some work was shifted into the more challenging winter months, which has lead to decreased productivity in late January 2008. Our Phase 1 Horizon Project completion cost forecast was revised to reflect this productivity decrease along with increasing cost pressures we faced as a result of choosing to get production on-line as targeted. After a thorough review, we have targeted Horizon Project's Phase 1 original $6.8 billion construction budget to increase 25-28%. Achieving this increase will result in an on-stream cost of less than $80,000 bbl/d – still an industry leader in capital efficiency.

The Company's plan for further development of Phases 2/3 of the Horizon Project involves a four-tranche approach, with targeted capacity of 232,000 to 250,000 bbl/d of SCO by 2013. The development plan for the Phases 2/3 expansion is characterized by smaller incremental projects. The execution strategy takes project

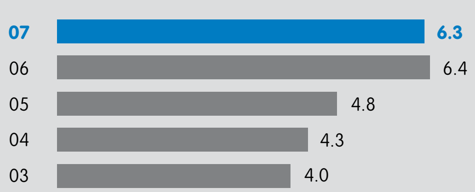
Cash flow from operations per share
(C$/share)



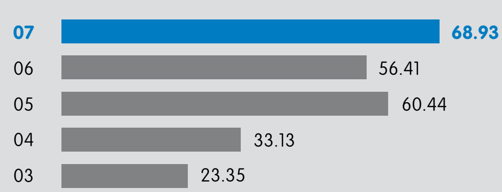
Daily production, before royalties, per ten thousand shares
(boe/d)



Conventional proved and probable reserves per share, before royalties
(boe)



Conventional net asset value per share
(C$/share)



control to the next level where Canadian Natural will complete the detailed engineering and design work, procure equipment, and award well defined, complete construction work packages. This strategy will take more time to complete but will ensure greater cost control while providing intermediate production gains, something we feel is vital in the current business environment. This plan for Phases 2/3 gives Canadian Natural better project control over execution and costs, and allows for greater capital flexibility. The incremental approach also aims to ensure the availability of the people and project teams to complete the expansion and allows for increased access to a greater depth of contractors, while maximizing our learnings from Phase 1. It will assist in maintaining the balance sheet strength of Canadian Natural and the ability to respond accordingly to commodity price fluctuations, while minimizing distraction for effective Phase 1 start-up and optimization.

Beyond Phase 1, Phases 2/3, and future phases of development are realistic extensions of the plan, ultimately targeting daily production of approximately 500,000 bbl/d of SCO from the leases. In total, we estimate reserves and contingent resources of 6 billion barrels of mineable bitumen at the Horizon Project.

FINANCIAL STRENGTH
A Core Element of our Business Strategy

Canadian Natural has long maintained that a strong balance sheet with the right amount of financial liquidity allows us to manage several 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.

As we look forward to 2008, we have a strong balance sheet that will continue to strengthen throughout the year. In addition, our liquid resources, represented by unused credit facilities, are appropriate for our current activity levels. We maintain a proactive approach to commodity hedging designed to meet or exceed our budget assumptions. This is to ensure cash flow from operations is sufficient to fund our capital programs. We remain committed to a diligent capital allocation process, developing those projects with the highest returns. This process inevitably leads us to developing and maintaining a large inventory of high quality opportunities.

We are aware that all business cycles will change and evolve, some more quickly than others, and that we are positioned to respond quickly and efficiently. Therefore, we remain committed to maintaining a strong balance sheet and the appropriate amount of financial liquidity.

DEFINED PLAN

The Canadian Natural team is proud to be able to provide a transparent strategy and growth profile to its investors. We target to continuously add value over an extended period reflected in each of our four per-share metrics by an average of 10% per annum and believe that we have the assets to deliver on it. We have a consistent history of strong, stable growth and through our measured approach will continue along the path of value creation.

In addition to the production growth aspect of the plan, our ability to allocate capital within our production mix from one commodity to another according to business cycle means that the economic sustainability of the organization is enhanced. The Defined Plan is not static, similar to our capital allocation practice, we adjust and refine our Plan to ensure returns are optimized. For example, our reaction to inflationary pressures has altered the timing of our organic natural gas expansion, while the acquisition of ACC lands increased short term production and greatly expanded the long term development potential of the organization. With respect to heavy crude oil developments and future phases of the Horizon Project, we will continue to steward capital in optimal fashion.

We have the assets and drive to significantly grow the business, but this will not occur at all costs. Project timing will be accelerated or delayed to optimize development economics. While we are currently benefiting from high commodity prices, we believe it to be irresponsible to assume this continues for planning purposes. And so we insist on more conservative price assumptions in our long-term planning models. Over the long term we still target 10% growth, but the current cost environment means that we must be even more diligent in optimizing the Plan as we continue to focus on value growth.

Management would like to again thank our entire team for continuing to deliver the Plan. We believe that Canadian Natural has the Assets, the Plan and the People to continue to deliver shareholder value for years to come. As a team, we remain committed to "developing people to work together to create shareholder value by doing it right with fun and integrity".

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

Our World-Class Team

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

Lonnie Abadier, Walday Abeda, Trevor Ackerman, Janine Adams, Mike Adams, Debra Addinall, Adetokunbo Adebayo, Yemisi Adebayo, Kike Aderibigbe, Richard Adzabe Ella, James Agate, Gerardo Aguirre, Sarshar Ahmad, Sarah Aho, Garrisen Ailsby, Fiona Aitken, Sina Akinsanya, Joseph Albano, Chris P Alderson, Bruce Alexander, Gregory Alexander, Daniel Alfred, Elena Algazina, Mohieddin Alghazali, Arshad Ali, John Allan, Jill Allen, John Allen, Trent Allen, Simon Allerton, Simon Allerton, Devin Allibone, Karen Almadi, Michael Almasi, Gordon Almond, Robert Almond, Jocelyn Alonso, Nelson Alook, Cindy Alpaugh, Laurel Alston, Arturo Alvarez, Ulises Amador, Gregory Amalia, Joann Aman, Traore Amara, Clark Ambler, Jonah Amedu, Donald Ames, Roxanne Amrolia, Sylvia Anaka, Jan Andersen, Troy Andersen, Allan Anderson, Georgina Anderson, Jeremy Anderson, Kelvin Anderson, Kristin Anderson, Leonard Anderson, Linsey Anderson, Murray Anderson, Perri Anderson, Richard Anderson, Steve Anderson, Peter Andrekson, Janet Andrew, Bob Andrews, Todd Andrews, Sherley Angers, Carolyn Angus, Shehzad Anjum, Kathryn Anthony, Helen Antle, Kathy Antonishyn, Shelley Antonuk, Richard April, John Argan, Humberto Arias, Juan Arizaleta, James Arkley, Anthony Armstrong, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Monique Arsenault, Paul Arsenault, Bala Arunachalam, Randy Aslin, Jim Asmus, Steven Aspden, Jacqueline Asso, Victoire Assohou-Ooattara, Francklin Assoko-Mve, Andrew Astalos, Maguy Atheba, John Atkinson, Edwin Au, Gordon Au, Jason Auch, Bernard Auger, Richard Augustyn, Ryan Austin, Maria Avila, Kevin Babuik, Adrian Baciulica, Michael Baddeley, MaryAnn Baes, Babak Baghban, Alex Bagnall, Brian Bahlieda, Dave Baier, Janice Baik, Michael Baik, Dwayne Bailer, Rod Bailer, Judy Bailey, Robert Bain, Chris Baker, Dayne Baker, Shane Baker, Sharon Baker, Reginald Baldock, Christopher Baldwin, Mark Baldwin, Robert Baldwin, Vaughn Baldwin, Joel Balkam, Gary Ballas, Ronnie Ballas, Sheldon Ballas, Brenda Balog, 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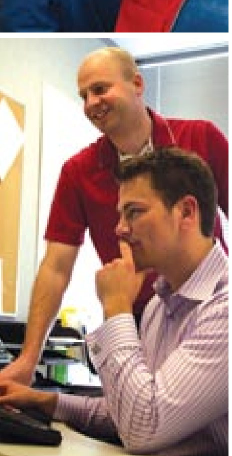

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Toor, Domenic Torriero, Michael Tosio, Chyndelle Toth, Derek Toullelan, Johnathan Toy, Paige Tracey, Sabrina D Trafiak, Brittany Trask, Catherine Trenouth, Brian E Trimble, Amy Trinh, Duc Trinh, Ray Trombley, Len Trotzuk, Ruaidhri Truter, Lisa Tsimaras, David Tuite, Sunny Tulan, Brent Tulloch, Neil Tulloch, Bruce Tumbach, George Tunnicliffe, Art Tupper, Terry Turgeon, Trent Turgeon, David Turk, Dick Turnbull, Barb Turner, Ruth Turner, Stanley Turner, Brian Turpin, Darren Turpin, Veronika Turska, Mark Tustian, Irene Tutto, Cary Twardy, Dave Tweddell, Gordon Twin, Oleg Tyan, Wayne Tymchuk, Shaun Tymchyshyn, Kenechukwu Ufondu, Eric Ulrich, Janis Underdahl, Nathan Underwood, Karl Unger, Earl Ungeran, David Unruh, Jackeline Urdaneta, Anand Vaidyanath, Allan Valentine, Gary L Valiquette, Louis Vallee, Michael Vallee, Anna Valmadrid, Vyvette Vanderputt, Christina VanderPyl, Bryant VanIderstine, Henk-Jan vanKlinken, Vicki VanOrman, Salomon VanRensburg, Collin Vare, Michael Varga, Daniel Vasseur, Nicolette Vaughan, Laureen Vaughan-Kirk, Randy Vegso, Steve Venus, Sheila Verigin, Natalia Verkhogliad, Dan Verleyen, Nancy Tay Vetrici, Cesar Viana, Bonnie Vickery, Dale Vickery, Wilf Vielguth, Angu Vifansi, Christine Viljoen, Marvin (Joe) Viola, Dean Vipond, Bill Virus, George Virus, Mark Virus, Santosh Vishwakarma, Tony Vitkunas, James W Vollman, Mel Vollman, Leo Vollmin, Luke Vondermuhll, Chrystal Voortman, Richard Wack, Kyle Waddy, Todd Waggoner, Trevor Wagil, Joy Wagner, Juon Wah, Lee Wahl, Donald Wakaruk, Lance Wakefield, Michael Lane Wakefield, Kevin Wakulchyk, Jeff Walden, Dave Waldner, Darcy Waldo, David Wales, David Walker, David Walker, Martin Walker, Dean Wall, Erin Wallace, Greg Wallace, Kevin Wallace, Vince Wallwork, Lorie Walter, Roger Walton, John A Wandler, Jinghao Wang, Selina Wang, Xiang Wang, Xing Zhu Wang, Blaise Wangler, Kathy Ward, Kirk Ward, Terry Ware, Wayne M J Warholik, Chris Wark, Wanda Warman, John Warrell, Michael Warrick, Faye Warrington, Paul T 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Evgeny Zhuromsky, Brenda Ziegler, Dwayne Zilinski, Megan Zilkey, Aaron Zubot

Review of Operations

Production

The strength and success of Canadian Natural's Defined Plan was demonstrated once again in 2007. By maintaining large project inventories in every product and basin in which we operate, the Company has been able to continually high grade its capital allocation process, achieving optimal value in each of the commodities we produce, namely, natural gas, light/medium crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil. Maintaining that balance is integral to our management's strategy – balance within the product mix and project time horizons, along with balancing growth through the drill bit and acquisition.

During 2007, production before royalties was 609,206 boe/d, up 5% from 2006 levels. This was achieved through a combination of asset development, exploration and a full year of production from the assets acquired through the purchase of ACC. Despite a scaled back natural gas drilling program, natural gas production before royalties increased by 12%, averaging the year with production of 1,668 mmcf/d. Total crude oil and NGLs production before royalties averaged 331,232 bbl/d.

Strategic Land Base

Canadian Natural has the second largest undeveloped land inventory in the WCSB, with undeveloped net acreage in excess of 12 million acres, excluding leases at the Horizon Project. The strength of the Company's land base is a result of continued land purchases, strategic acquisitions including the incorporation of the ACC properties that were acquired in late 2006. This strong concentrated land base affords significant opportunities to control operating costs, along with minimizing finding and on-stream costs. The vast 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.

	2007		2006	
	Production	**Mix**	Production	Mix
(before royalties)	mboe/d	%	mboe/d	%
Natural gas	**278**	**45**	249	42
North American light/medium crude oil and NGLs	**57**	**9**	51	9
Pelican Lake crude oil	**34**	**6**	29	5
Primary heavy crude oil	**92**	**15**	91	16
Thermal heavy crude oil	**64**	**11**	64	11
North Sea light/medium crude oil	**56**	**9**	60	10
Offshore West Africa light/medium crude oil	**28**	**5**	37	7
Total	**609**	**100**	581	100

CORE LANDHOLDINGS

	2007			2006		
(thousands of acres)	**Gross**	**Net**	**%**	Gross	Net	%
North America						
Developed	**8,255**	**6,424**	**78**	8,062	6,366	79
Undeveloped	**14,782**	**12,160**	**82**	15,848	12,785	81
North Sea						
Developed	**122**	**88**	**72**	138	93	67
Undeveloped	**356**	**287**	**81**	367	299	81
Offshore West Africa						
Developed	**7**	**4**	**57**	7	4	57
Undeveloped	**247**	**206**	**83**	247	207	84
Total						
Developed	**8,384**	**6,516**	**78**	8,207	6,463	79
Undeveloped	**15,385**	**12,653**	**82**	16,462	13,291	81
	23,769	**19,169**	**81**	24,669	19,754	80

The infrastructure associated with this vast, concentrated 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.

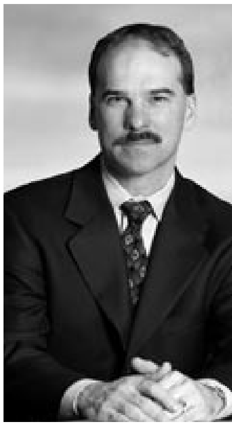
Geo-Science Strategy

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. The integration of seismic interpretation, geology, and innovative engineering, results in our successful annual drilling program, and a consistent net increase of new high quality locations to our conventional and unconventional inventory. We invested $67 million during 2007 to acquire new seismic, and to purchase and reprocess existing seismic data. In total, 2,012 kilometers of conventional 2D seismic data and 379 square kilometers of 3D seismic data were acquired. Additionally, 8,778 kilometers of conventional 2D seismic data and 2,532 square kilometers of 3D seismic data were purchased internationally and domestically. 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 [1] (net wells)	
	2007	2006	**2007**	2006
Canadian conventional				
Northeast British Columbia	**2,401**	2,721	**61**	196
Northwest Alberta	**1,489**	1,750	**126**	194
Northern Plains	**6,626**	6,804	**636**	728
Southern Plains	**925**	870	**169**	120
Southeast Saskatchewan	**121**	117	**28**	75
In-situ Oil Sands	**483**	407	**192**	247
	12,045	12,669	**1,212**	1,560
Horizon Oil Sands Project	**115**	116	**98**	163
United Kingdom North Sea	**287**	299	**7**	9
Offshore West Africa	**206**	207	**5**	6
	12,653	13,291	**1,322**	1,738

(1) Includes stratigraphic test and service wells.



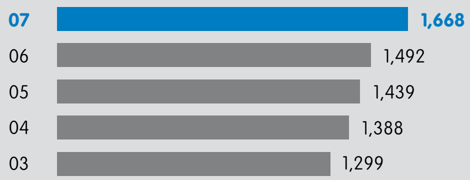
"Being the low cost producer, focused in our core areas, and operating our assets are key to creating shareholder value."

Tim S. McKay
SENIOR VICE-PRESIDENT, OPERATIONS

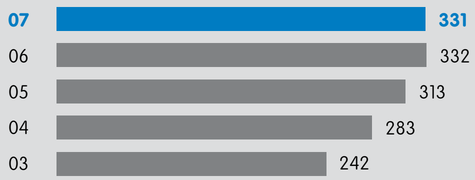
"As the second largest undeveloped land holder in the Western Canadian Sedimentary Basin we proactively manage our diverse asset base for future growth."

Mary-Jo E. Case
VICE-PRESIDENT, LAND

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



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



Drilling Activity and Strategy

In 2007, we saw stabilization and in some cases a reduction of costs within the western Canadian industry, with natural gas drilling costs showing a decrease. The stabilization was in response to industry-wide pressure placed on the services through several scaled back drilling programs, weaker natural gas prices, uncertainty surrounding Alberta's Royalty Review and the impact that it may have on demand for drilling supplies and services. Looking specifically to natural gas, efficiencies were gained and our natural gas drilling program returned results that exceeded expectations – a result of better crews, better equipment and by nature of our deep, high quality prospect inventory. Costs in crude oil related services continue to remain high, but stable.

As the price of crude oil steadily escalated throughout 2007 and the heavy oil differential remained favourable, capital continued to be allocated towards higher return crude oil projects. This was counter to the weaker natural gas price throughout the year where we saw a decline in natural gas production and a decrease in overall wells drilled.

With the economics of drilling for natural gas eroded by the proposed changes to Alberta's royalty regime along with relatively low natural gas price, our natural gas drilling program will once again decrease throughout 2008 by approximately 30%. The decrease in drilling activity will be in Alberta, where the focus will shift from conventional and deep natural gas wells to shallow natural gas and CBM wells. Natural gas activity outside of Alberta is targeted to increase by 8%, due mainly to the development program in the Hatton region of Saskatchewan. The trend towards increasing drilling activity outside the province of Alberta continues in our crude oil drilling program with a 22% reduction within Alberta, and 30% increase in British Columbia, Saskatchewan and Manitoba.

"We have the financial strength to grow our assets and have the ability to take advantage of strategic opportunities."

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

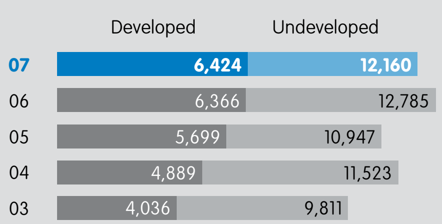
WELLS DRILLED

Year Ended December 31	2007			2006	
	Gross	**Net**	**Success**	Net	Success
Crude oil – North America					
Light crude oil	**80**	**63**	**94%**	113	92%
Pelican Lake crude oil	**126**	**126**	**99%**	144	100%
Primary heavy crude oil	**383**	**340**	**94%**	274	94%
Thermal heavy crude oil	**55**	**55**	**100%**	60	98%
North Sea light crude oil	**4**	**4**	**100%**	8	100%
Offshore West Africa light crude oil	**7**	**4**	**100%**	4	100%
	655	**592**	**96%**	603	95%
Natural gas – North America					
Northeast British Columbia	**52**	**42**	**74%**	163	90%
Northwest Alberta	**125**	**98**	**88%**	155	88%
Northern Plains	**113**	**96**	**72%**	219	84%
Southern Plains	**188**	**147**	**99%**	104	93%
	478	**383**	**85%**	641	88%
Dry	**107**	**93**		119	
Subtotal	**1,240**	**1,068**	**91%**	1,363	91%
Stratigraphic test/service wells	**256**	**254**		375	
Total	**1,496**	**1,322**		1,738	

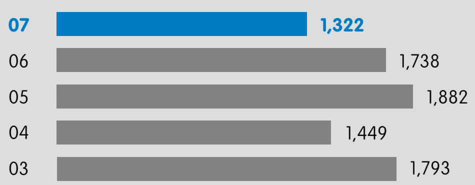
"Capital discipline is essential to provide returns over the long term."

Randall S. Davis
VICE-PRESIDENT, FINANCE & ACCOUNTING

Total North America landholdings
(thousands of net acres)



Total net wells drilled



Marketing

Natural Gas

Canadian Natural's gas marketing objective is to maximize the realized price for its overall portfolio. Our strategy is anchored by solid business relationships based on demonstrated performance and integrity, while working together with our customers to meet their needs. We market primarily to large credit worthy utilities, industrial and commercial customers across North America. The current portfolio includes 11% of direct sales to various American customers, 79% sold directly into our domestic markets with the remaining 10% going to the Alberta-based gas supply and market aggregators. Canadian Natural's portfolio is essentially driven by current market prices with over 99% of all sales fluctuating with the pricing index prevailing at the points of physical delivery of the gas. The marketing team monitors regulatory applications by the pipeline companies and participates as necessary to ensure an optimal outcome is achieved for all stakeholders.

Canadian Natural's realized wellhead price in 2007 was 2% higher than in 2006 at $6.85/mcf despite the AECO and NYMEX index both falling by 5% and the average Canadian dollar strengthening relative to the American dollar by 6% in 2007. This was primarily due to the physical forward sales entered into for 2007. The first quarter weather caused the North American natural gas storage inventories to drop below 2006 levels which supported prices for the first half of the year. The softer gas markets in Europe and Asia provided attractive opportunities to export LNG to the US facilities which resulted in an estimated total incremental supply of 150 bcf. With lower demand during the second half of 2007 caused by relatively benign weather and slower economic growth, pricing levels weakened.

Strong drilling activity in the US during 2007 resulted in an incremental supply of 1.2 bcf/d. In western Canada, 17% fewer wells were drilled in 2007. As such overall natural gas production in the WCSB declined by 450 mmcf/d in 2007 and continues to further decline in early 2008. Overall demand in North America was up by roughly 5 bcf/d in 2007 with several power generating units coming online in the US, along with increased demand coming from Canadian oil sands operations and heavy oil thermal projects. Two significant developments will add North American incremental supplies in 2008: the Independence Hub off the coast of Louisiana is

expected to add 1.0 bcf/d and the Rockies Express Pipeline will allow 0.5 bcf/d of natural gas to reach Midwest and North East markets. This is in contrast to the continued declines observed from the WCSB.

Additional LNG terminals and vaporization facilities to be completed in 2008 will add up to 6.0 bcf/d of additional capacity in the US. Many natural gas liquefaction plants are currently under construction around the world and a large fleet of specialized shipping vessels is being built to ensure logistics will not be an issue in the commoditization of LNG. Quantities imported into North American facilities are essentially dependent on higher prices in the US versus European and Asian markets. Current price forecasts suggest very modest LNG imports into the US for 2008. Gas supplies are adequate in North America with relatively soft prices, whereas LNG demand is very strong in the Asian markets.

"The demand for crude oil continues to be very strong out of Asia and we expect that to continue for the decade to come."

Réal M. Cusson
SENIOR VICE-PRESIDENT, MARKETING

Canadian Natural's natural gas production for 2008 is forecast to average 1,429 – 1,513 mmcf/d. With the 2008 corporate budget forecast of NYMEX at US$7.00/mmbtu and AECO at $5.68/GJ, this would yield an overall wellhead price of C$5.66/mcf for our sales portfolio, using an exchange rate of 1.00 for the US$/C$.

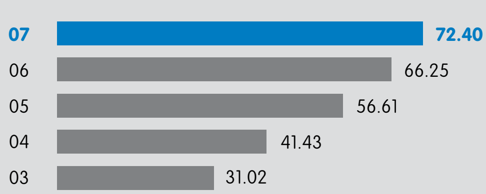
Crude Oil

Canadian Natural's crude oil marketing strategy is designed to unlock the value of our vast heavy oil reserves. The three major components of our strategy consists of blending various crude oil streams and diluents to better serve the needs of our refining customers, support and participate in the expansion of pipeline export capacity and to support and participate in projects adding incremental conversion capacity for bitumen and SCO.

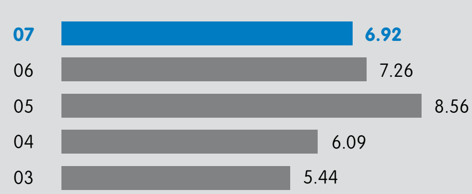
Canadian Natural's realized wellhead price increased by 3% in 2007 to $55.45/bbl, based mainly on continued worldwide demand for hydrocarbons and a constrained supply environment, with almost no spare capacity from the producers and full utilization of worldwide refining assets. The benchmark price for WTI crude oil was up 9% in 2007 to US$72.40/bbl and reached an all time high in 2007 of US$99.29/bbl on November 21. The benchmark for two thirds of the world oil traded, Dated Brent crude oil, was also higher than in 2006 by 11% to US$72.59/bbl based on strong European and Asian demand and unpredictable geopolitical events. The price differential for the Canadian heavy crude oil as measured by the Lloyd Blend ("LLB") price differential to the WTI index was 6% wider at 32% in 2007 than the average for 2006. The stronger commodity prices were largely offset by a Canadian currency that was 6% stronger in 2007. Canadian Natural continued to successfully implement its blending strategy in 2007 and contributed 55% of the average 257,000 bbl/d of the WCS stream in 2007.

The second phase of the marketing strategy entails geographic expansion of pipeline systems in an effort to open up new markets for heavy crude oil and SCO. These logistical challenges are being addressed by industry and significant progress was made in 2007. Both the Spearhead and Pegasus pipelines to Southern PADD III refining markets are running at capacity. The first phase of Trans Mountain Expansion 1 added 35,000 bbl/d to the west coast with a further 40,000 bbl/d, scheduled to be completed in the fourth quarter of 2008. Several other pipeline projects are in various stages of development and progress, ranging from preliminary commercial development to being under construction. We are very confident that the industry will proceed with the necessary incremental pipeline export capacity on a timely basis to support the expected incremental production out of the WCSB, and in particular, from the oil sands and heavy oil projects.

WTI crude oil reference pricing
(US$/bbl)



NYMEX natural gas reference pricing
(US$/mmbtu)

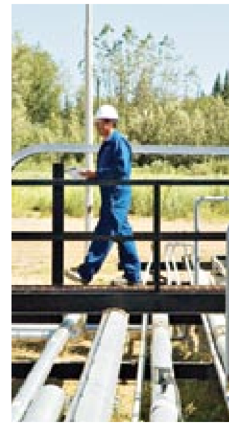


Canadian Natural's crude oil portfolio for 2008 is targeted to average between 316,000 bbl/d and 366,000 bbl/d. Based on the corporate budget forecast for WTI at US$73.00/bbl and 30% for the WCS heavy differential, this would yield an overall wellhead price of C$53.90/bbl.

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.

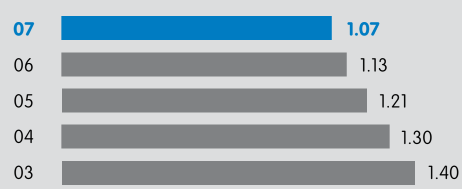
In conjunction with approval of the Horizon Project, our hedge policy allows up to 75% of any commodity's expected production volumes for a forward 12-month period, up to 50% of the second 12-month period and up to 25% for the following 24-month period. For further information on the particulars of this hedge program please refer to Management's Discussion and Analysis and the Consolidated Financial Statements.



Midstream

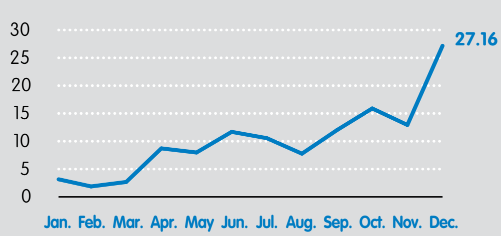
Our midstream assets consist of the 100% owned and operated ECHO Pipeline, a 15% interest in the Cold Lake Pipeline system, a 62% interest in the Company operated Pelican Lake Pipeline, and a 50% interest in the 84 megawatt co-generation unit located at our Primrose facility. The midstream assets allow us to control and optimize transportation costs for about 80% of our heavy crude oil production. It also generates additional revenue from third party volumes, along with the sale of surplus electricity. ECHO is the only pipeline delivering undiluted raw bitumen to the Hardisty terminals and plays an important role in our heavy crude oil blending and marketing strategy for WCS and other diluted bitumen blends. We are currently expanding our truck facilities at the Nipisi terminal to handle additional volumes from the Pelican Lake area.

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



LLB price differential to WTI
(%)

2007 Mayan - WCS spread
(US$/bbl)



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, environmental management and community support for our employees, contractors and shareholders. We recognize that health and wellness, safety, environmental and social considerations, are fundamental to our long-term growth.

Health and Safety

Canadian Natural conducts operations in a manner that protects the health and safety of employees, contractors, the public and the environment. Through our focus on safety programs and processes, we continue to enhance safety awareness. Statistically in 2007, Canadian Natural's health and safety performance benchmarks surpassed internal targets and continues to improve.

In our North American conventional operations, the total recordable injury frequency in 2007 continued the downward trend of the past five years, and is amongst the top performing Canadian peer companies.

Canadian Natural continues to have a very aggressive audit program. All internal audits are performed using a company-developed safety and compliance audit protocol. For our North American conventional operations in 2007, over 600 facility, drilling and service rig, pipeline and construction project audits were conducted, an increase of more than 100 over 2006. Our ongoing programs, including our internal audit program, have resulted in Canadian Natural maintaining an Energy Resources Conservation Board satisfactory inspection rate that is significantly better than the industry average.

At our Horizon Project, total recordable injury frequency decreased significantly even though the total exposure hours onsite increased by over 240% from 2006. The Horizon Project achieved 12 million hours lost time injury free in 2007. The Horizon Project's benchmarking results are aligned with our oil sands peer group during this intensive phase of development.

The Horizon Project health and safety team continued to focus on implementing programs such as safety pre-qualification of all contractors along with third-party prime contractor audits. As we continue commissioning in 2008, work continues on safety training programs and processes for employees and contractors, and the integration of emergency response plans with those of the regional municipality. An audit of the Horizon Project emergency response plan in 2007 found that our plans surpassed regulatory requirements.

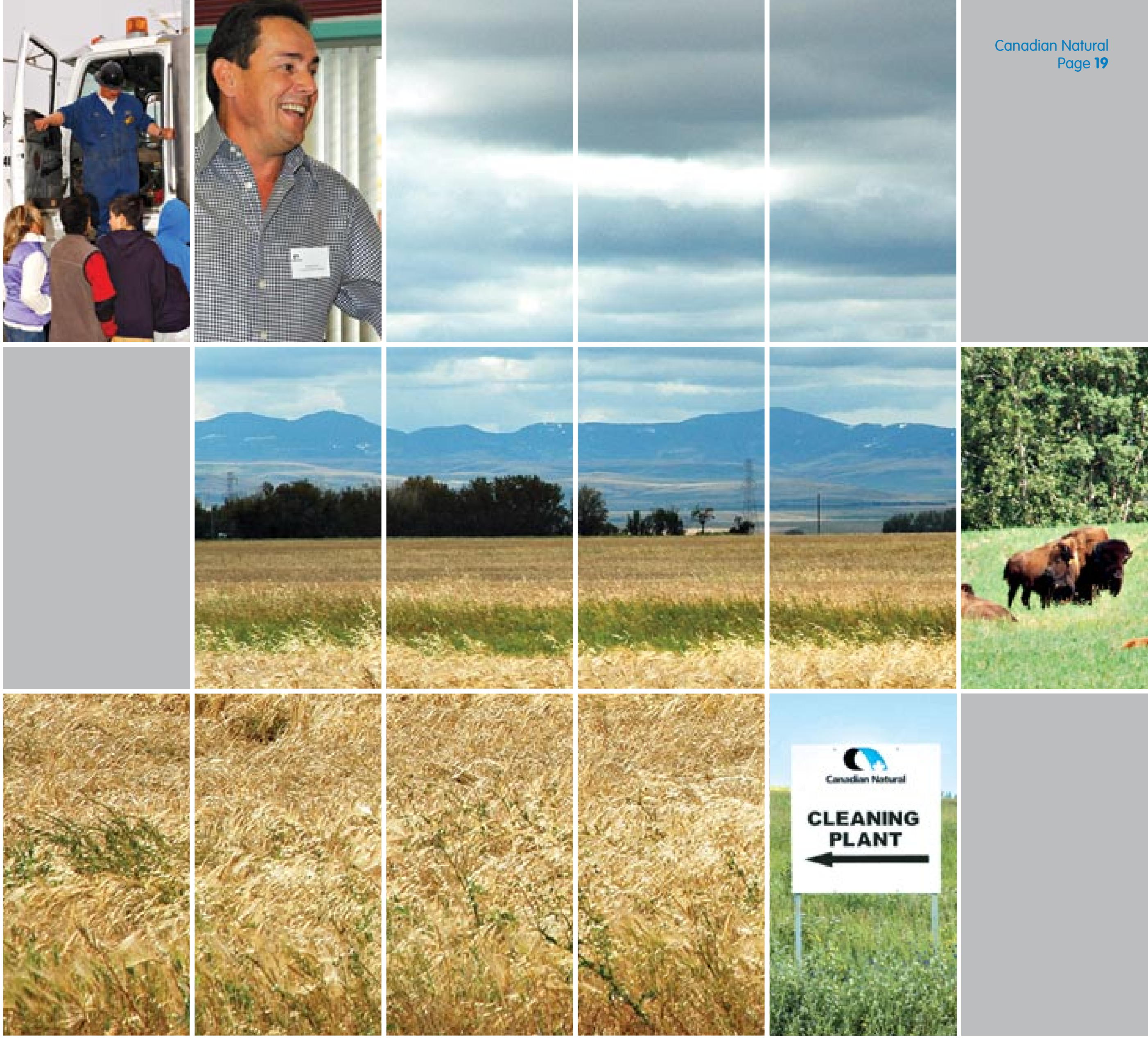
Internationally, Canadian Natural's benchmarking statistics are in the top quartile of UK North Sea operators, with 2007 total recordable injury frequency performance improving significantly over previous years. Initiatives aimed at further improving worksite safety behaviours and targeted safety leadership training have contributed to delivering this outstanding performance.

Integrity

Canadian Natural is committed to managing the integrity of its pipelines and facilities. For the North American conventional integrity group, tank testing, pipeline integrity, pipeline abandonment and discontinuation and pressure equipment are focal points. The Asset Integrity Program at the Horizon Project site has been

"Reducing our environmental footprint is a key consideration throughout our operations."

Lyle W. Stevens
SENIOR VICE-PRESIDENT, EXPLOITATION



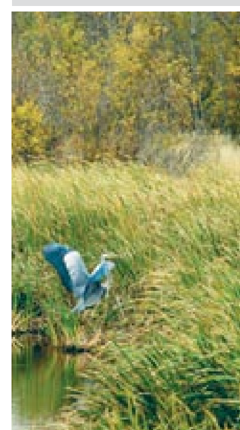
established to develop and implement the pressure equipment guidelines to meet corporate standards and regulatory requirements. Internationally managing the ongoing and future structural integrity of mature North Sea installations has been a significant focus. A third party audit of all international assets has shown that Canadian Natural's UK asset integrity performance is good with respect to other North Sea operators.

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, liability reduction, air emission management, reduction of fresh water use, minimizing of our landscape footprint and operations compliance.

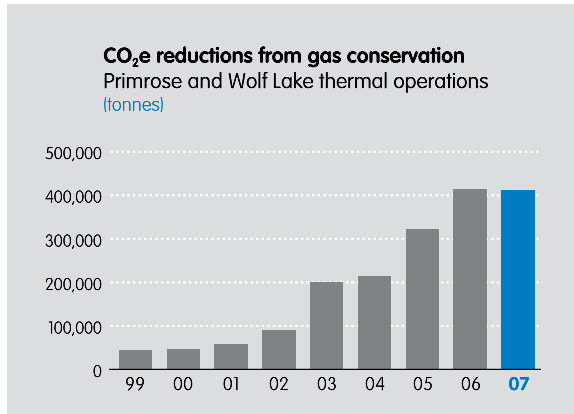
We continued the development of our enhanced Environmental Management System ("EMS") for the Horizon Project and our conventional operations in 2007. The EMS focuses on ensuring our field operations minimize their environmental impact and meet all corporate standards and regulatory requirements.

For North American conventional operations, our liability reduction programs focus on abandonment, reclamation and decommissioning activities. In 2007, we abandoned 669 wells. 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. Ongoing efforts to increase brackish and saline water supplies will reduce freshwater demand at Primrose Wolf Lake by 73% by 2013, relative to 2006 levels.



In 2007, the Horizon Project continued with several environmental management programs, including monitoring of soils, fisheries and water quality; a weekly environmental inspection program of construction sites; and a wildlife management program. An ambient air monitoring station, tied into the Wood Buffalo Environmental Association for monitoring, maintenance and data reporting, was installed adjacent to the Horizon Project site. The fish habitat Compensation Lake dam was completed and work began on fish habitat construction. Minimizing the overall environmental footprint remains a priority for the Horizon Project.

Internationally, we extended our ISO 14001 environmental certification to Ninian Central and maintained certification on Tiffany, Balmoral and Ninian Northern. Total oil in produced water discharged to sea was reduced by over 40% from 2006, due to a combination of regulatory changes to the analytical method and significant improvements in produced water handling. The successful produced water re-injection trial at Ninian Central platform continues, re-injecting 30,000 bbl/d of produced back into our producing formations. In 2008, we will evaluate extending this program to other offshore platforms as part of our strategy to reduce all discharges to sea.



Canadian Natural is committed to developing innovative and effective solutions to manage GHG emissions and air quality issues. Implementation of flaring, venting, fuel and solution gas conservation programs continue. In 2007 we completed approximately 115 natural gas conservation projects in our North American conventional operations, resulting in the reduction of 1.28 million tonnes/year of CO_2e. Over the past five years over $116 million has been spent to conserve the equivalent of over 6.4 million tonnes of CO_2e.

To date, Canadian Natural has invested over $82 million in natural gas conservation in the Primrose and Wolf Lake areas resulting in a GHG reduction of approximately 417 kilotonnes of CO_2e emissions annually.

The Horizon Project will incorporate numerous advancements in technology to reduce GHG emissions including the research, development, and implementation of a process to sequester CO_2 into tailings. At the completion of Phases 2/3, we believe this process will eliminate approximately 180,000 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 corporate web site.

Community

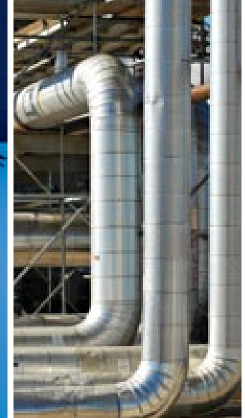
Throughout our operations we work with our neighbours to minimize the impacts of our activities, while enhancing local and regional benefits. Canadian Natural is committed to building and maintaining strong, co-operative working relationships, and establishing a positive presence in the communities where we operate.

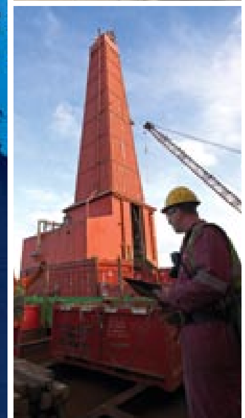
In 2007, we continued to work together with our stakeholders in an effort to develop relationships built on respect and trust. Our aim is to understand our stakeholders' interests so we can consider and incorporate their feedback into current and planned operations.

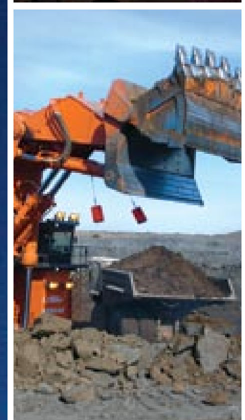
Education and training are fundamental to developing people. Throughout our operations, Canadian Natural supports a number of initiatives in building labour capacity in communities to meet the long-term human resource needs in the crude oil and natural gas industry. In 2007 we supported programs such as the Petroleum Employment Training Program, 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. Since the program's inception in 2002, we have awarded over $600,000 to more than 440 students.

We work with our communities in western Canada, the UK and West Africa to provide financial and volunteer support for the projects that meet their vision for the future, and contribute to building strong communities. Overall, Canadian Natural's community sponsorship and funding support totaled more than $4.6 million in 2007.

The Assets







Defined Strategy to Exploit a World-Class Asset Portfolio

Low risk exploitation drives the development of our vast resource base. It has proven to be successful through the business cycle as a result of minimizing exploration risks, maintaining low operating costs and reducing capital costs. This disciplined approach is applied rigorously throughout our worldwide operations, and features:

- Maintaining a large inventory of undeveloped land in each core region facilitating the continual high-grade prospects and optimize drilling programs;
- Dominating the land base and controlling the infrastructure in regions wherever we operate. Maintaining high working interests and operating the vast majority of the assets allows us to steward to our development plans and control costs;
- Progressively developing lands as extensions to existing infrastructure, thereby minimizing infrastructure costs and maximizing existing facility utilization;
- Maximizing resource recovery through the application of proper production practices and tertiary recovery techniques; and
- Pursuing opportunistic acquisitions that provide future growth opportunities and complement expertise and existing assets.

"We are unique in being exposed to both conventional and unconventional opportunities both domestically and internationally."

Jeff W. Wilson
SENIOR VICE-PRESIDENT, EXPLORATION

"A balanced product and project portfolio allows for flexibility."

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

North America

	2007 net, after royalties	
	Production (mboe/d)	Proved reserves [1] (mmboe)
Crude oil and NGLs	211	920
Natural gas	230	587
Boe	441	1,507
% of total	84	77

International

	2007 net, after royalties	
	Production (mboe/d)	Proved reserves [1] (mmboe)
Crude oil and NGLs	82	438
Natural gas	4	24
Boe	86	462
% of total	16	23

Horizon Project Mining

	2007 proved reserves [1]	
	Gross Lease (mmbbl)	Net (mmbbl)
Bitumen	2,385	1,995
SCO [2]	1,956	1,761

(1) Based on constant prices and costs.
(2) SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

North America

- Canadian Natural has the second largest undeveloped land base in the WCSB and a dominant position in infrastructure.
- Today, we have over 8,000 natural gas locations in our inventory, a reflection of our strong asset base.
- We have 300,000 bbl/d of incremental crude oil projects to develop from our thermal heavy oil asset base. The value of these barrels has increased dramatically with narrowing heavy oil differentials and higher overall crude oil pricing.
- The Horizon Project is poised to come on stream in Q3/08 – delivering 110,000 bbl/d of SCO.

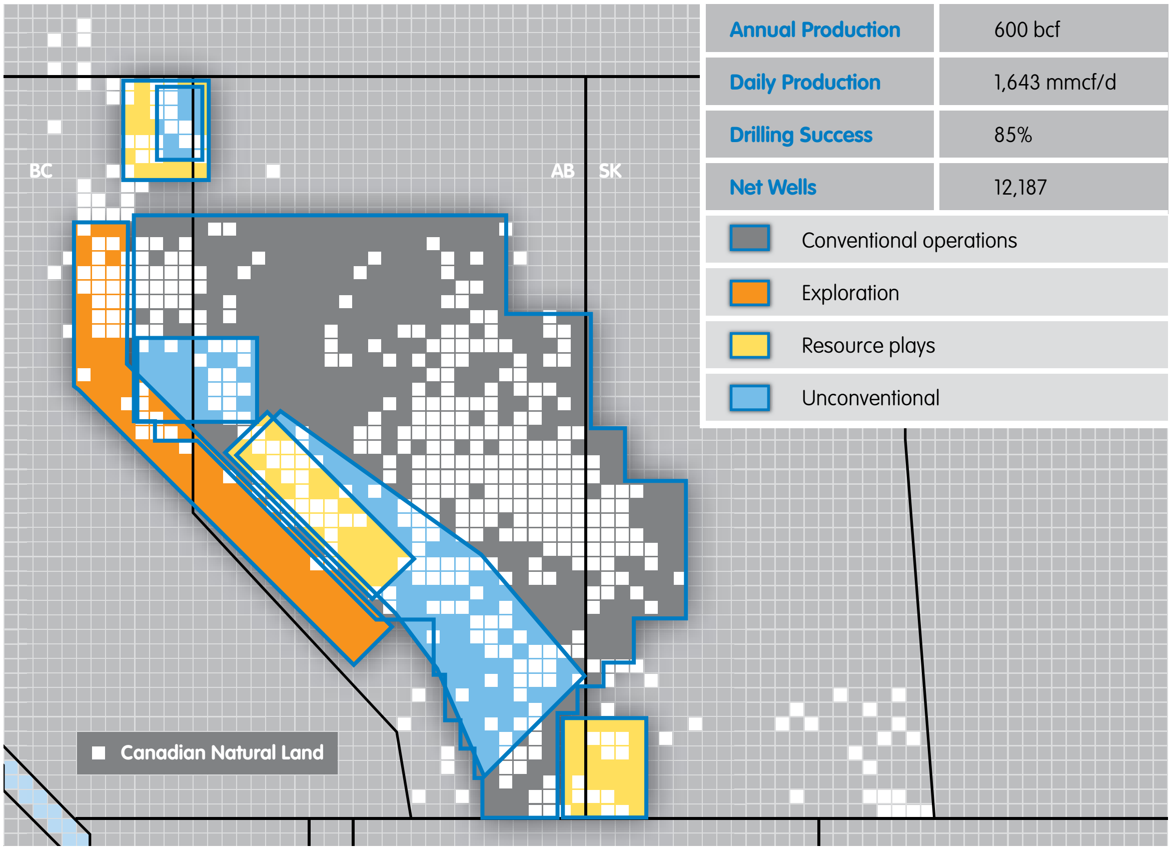
North Sea

- By using our expertise in mature basin exploitation, Canadian Natural delivers strong, steady production of light crude oil from our North Sea assets.

Offshore West Africa

- Delivering some of the highest returns on capital in the Company, we currently have three producing properties – East Espoir, West Espoir and Baobab, all located in offshore Côte d'Ivoire. Development of the Olowi Field in offshore Gabon is on track with first oil scheduled for Q4/08.

North American Natural Gas



Annual Production	600 bcf
Daily Production	1,643 mmcf/d
Drilling Success	85%
Net Wells	12,187

- Conventional operations
- Exploration
- Resource plays
- Unconventional

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

Canadian Natural is the second largest producer of natural gas in Canada with average production of 1,643 mmcf/d in 2007. Our natural gas production represents 45% of our total production based on a barrels of oil equivalent. During 2007, average production volumes increased over 2006 volumes by 175 mmcf/d or 12%, reflecting our high-graded, high-quality asset base, a successful drilling and development program and the full year impact of ACC properties. Canadian Natural's natural gas strategy maximizes value by balancing capital allocation between our extensive inventory of low risk conventional opportunities and development of new natural gas resources. This strategy allows us to incorporate new plays into our portfolio at a measured rate while continuing to provide low risk and reliable cash flow. Our balanced production portfolio proved beneficial with $64 million being reallocated from the natural gas drilling program, into higher netback crude oil projects. Even with this capital reduction on natural gas spending, we were able to exceed our budgeted production numbers for the year.

2007 proved to be a challenging year for natural gas. It was a year of restraint, but also a year of steady progress towards the development of key natural gas projects. Canadian Natural anticipated many of the challenges faced during 2007 and used our strong natural gas assets to provide the flexibility necessary for success in the current environment. Our high graded program allowed us to drive down our costs and exceed performance targets for 2007. We have been encouraged by our strong performance and are planning for continued improvement in 2008. We will expand our inventory of prospects to ensure the success of our natural gas program in future years.

Northeast British Columbia

Canadian Natural is the second largest holder of undeveloped land in British Columbia with 2.4 million net undeveloped acres, which along with our infrastructure allows us to minimize costs. A large resource potential exists across a variety of conventional shallow and deep plays, as well as unconventional play types. The 2007 focus has been on lower risk natural gas plays and we have also pursued low cost development opportunities to add production volumes. These included optimizing existing producing wells at Fort St. John West, Caribou and Adsett resulting in incremental production exceeding 17 mmcf/d. Development of the regionally extensive unconventional Montney play commenced in 2007 and we are anticipating significant production by 2010. In addition, initial evaluation of the shale gas potential present on our lands occurred in our northern BC area.

Northwest Alberta

Northwest Alberta is a rich, multi-zone natural gas producing region. Canadian Natural's large undeveloped land base of 1.5 million net acres in conjunction with 26 operated facilities and an extensive pipeline network provides a significant competitive advantage. We continue to expand the vast potential of the Deep Basin gas play on Canadian Natural's significant acreage position. Our large, cost effective, repeatable drill programs will economically develop new gas resources for many years to come. Working towards significant cost improvements has been a major focus in 2007. In Wild River, well costs have been reduced by more than 25% as a result of drilling and completion optimization, service industry cost reductions, effective planning and the use of volume discounts. Technology has also played a major role throughout 2007. Significant advancements have been made improving completions, with commingling and limited-entry fracture stimulations, and proving the economic viability of low risk infill drilling in some regions. We will continue to leverage our existing developed areas to identify potential follow-up drilling programs. In the Peace River Arch, Canadian Natural will continue to exploit dual, tight gas targets in the Doig and Montney formations. A combination of step out and downspaced vertical wells that target multi-zone, liquid rich natural gas prospects will maximize the value of Canadian Natural's strategic processing capacity in the area.

Foothills

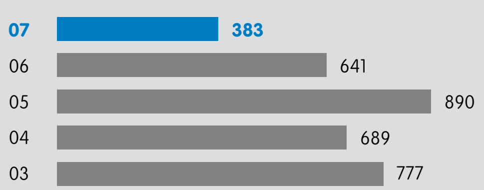
The Foothills is one of Canadian Natural's key growth areas for natural gas. We have an excellent inventory of prospects within this area and we have the expertise to develop this large, technically challenging resource base. During 2007, we have increased our infrastructure position and have acquired acreage on two new undeveloped structures. We have also acquired a significant amount of 3D seismic data to expand our opportunity base of complex, yet, highly rewarding prospects in our core focus area. Our 2008 drilling program for the Foothills focuses on areas with existing Canadian Natural infrastructure to further leverage what we own and operate.

Northern/Southern Plains

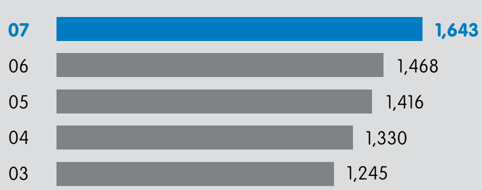
The Plains natural gas core region contains shallow to moderate depth, multi-zone conventional exploitation plays, extensive shallow gas resource plays and unconventional CBM plays. Our shallow gas program is characterized as having low geological risk, with long reserve life. Our CBM assets consist of low risk proven Horseshoe Canyon coals and the evolving Mannville coal play.

In 2007 there have been capital cost reductions in the Plains area, particularly in the CBM projects. We have seen reductions through most of the value chain, including 25-30% reductions in drilling costs, 30-40% reductions in completions costs, and 15-17% reductions in tie-in costs. We look to CBM and shallow gas to provide significant natural gas drilling opportunities. Conventional multi-zone plays will also continue to deliver recompletion and drilling potential. In 2008 we will continue testing the Swan Hills Mannville CBM pilot and we'll commence downspacing for shallow gas in Hatton. Canadian Natural will continue to access and develop new natural gas opportunities, focus on growing our location inventory and optimizing all our natural gas production assets throughout 2008.

North American successful natural gas wells drilled
(net wells)

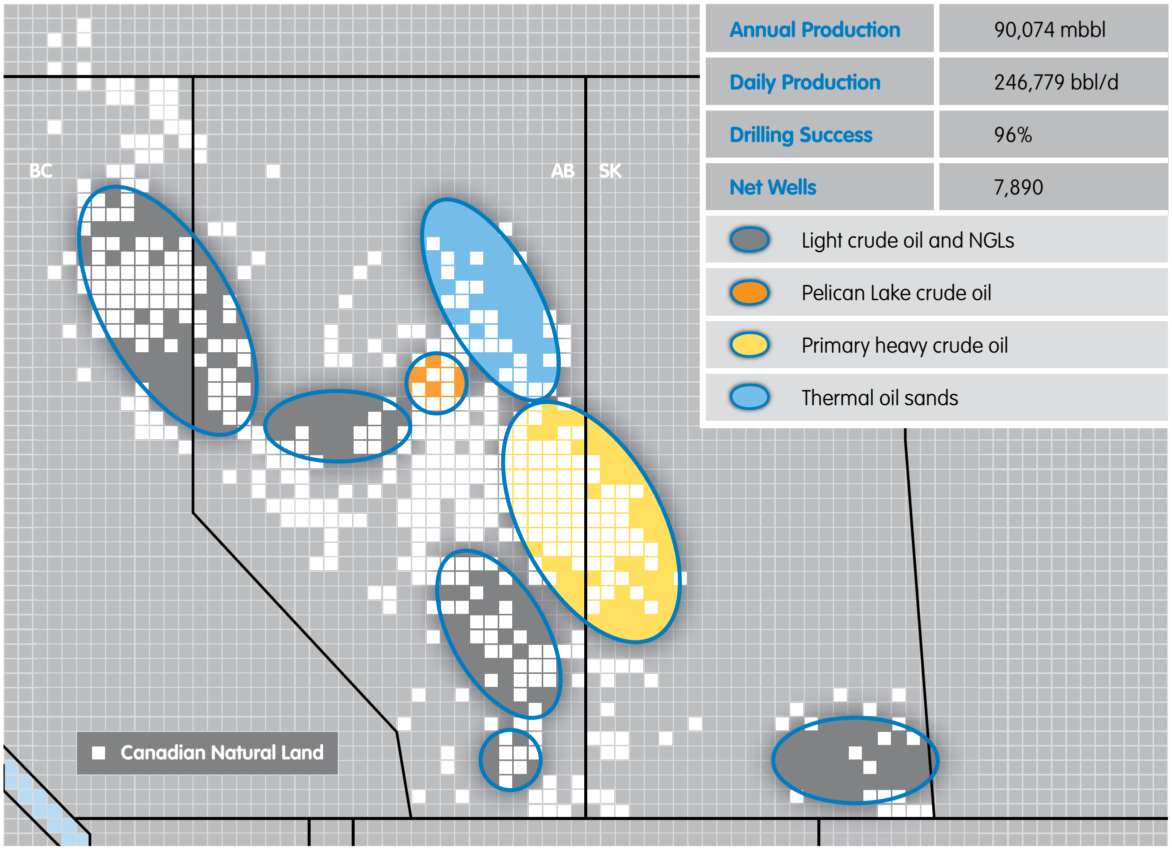


North American natural gas production, before royalties
(mmcf/d)



North American Crude Oil and NGLs

Annual Production	90,074 mbbl
Daily Production	246,779 bbl/d
Drilling Success	96%
Net Wells	7,890



Canadian Natural is the largest producer of heavy crude oil in western Canada. Our production is a blend of light crude oil, heavy crude oil and NGLs, which are produced in conjunction with natural gas. In 2007, North American crude oil and NGLs represented 41% of the Company's total production. The depth of our crude oil asset base and the importance of our balanced product portfolio were revealed once again in 2007 when we concentrated our drilling and development activity on crude oil rather than natural gas as a result of commodity prices. Even within our crude oil assets, we maintain a balance between light, medium and heavy crude oils giving us the flexibility to allocate capital and activity to the projects with the greatest returns.

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

Our light crude oil assets are relatively mature, however, we continue to add significant reserves by leveraging proven technologies to maximize the value of our extensive asset base. The vast majority of the Company's light pools are produced under waterflood resulting in high recovery factors with low production decline rates. We continue to evaluate and field test EOR technologies on several pools to further enhance crude oil recovery.

In 2007, Canadian Natural's light crude oil drilling and development programs continued to pursue three main initiatives within western Canada:

- 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 the Southeast Saskatchewan;

- Waterflood optimization programs. Our strong technical team continues to improve the performance of our waterfloods through detailed reservoir characterization and analysis of performance data; and
- Continued EOR focus. We have continued with our pilot test of polymer flooding to improve crude oil recovery in a mature waterflood like the Horsefly/Taber pool and we continued the CO_2 pilot flood on the Enchant pool in the Southern Plains. We are also evaluating applications of these technologies in other Canadian Natural owned and operated light crude oil pools.

For 2008, Canadian Natural will continue to execute its defined development plan for light crude oil with a focus on continued optimization of existing waterfloods and development of tertiary recovery processes. We will continue with testing polymer flooding and CO_2 flooding at our ongoing pilot projects and will begin the evaluation of commercial opportunities of the most promising technologies. Our asset base continues to provide excellent opportunities to add reserves through low risk infill and step-out drilling. In 2008, we are planning to drill more than 75 wells in our light crude oil program across western Canada.

Pelican Lake Crude Oil

The Pelican Lake asset is a massive crude oil pool in our Northern Plains core region. This area continues to deliver excellent opportunities for production and reserves growth anchored by a pool with greater than four billion barrels of OOIP on our developed working interest leases. We have developed this pool exclusively with horizontal wells to minimize the environmental impact, reduce development costs and provide greater well productivity. Although initially developed for primary production, the pool has proven to be amenable to EOR with commercial success in both waterflooding and polymer flooding. In the last three years, testing of waterflooding and polymer flooding has proven that we can double recovery in many areas of the pool.

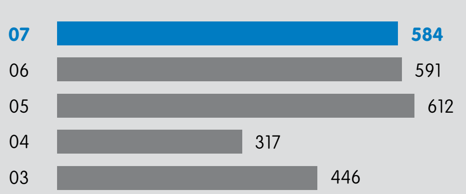
In 2007, the Company continued with the development of primary production drilling 94 primary horizontal crude oil wells. Success with polymer flooding has led Canadian Natural to transition from waterflooding to polymer flooding in many areas of the pool. The improved mobility ratio achieved with polymer flooding results in improved sweep efficiencies and higher recovery factors. We have begun to convert existing waterflood patterns to polymer flood and initiated conversion to polymer flood in several new areas of the pool. Production in 2007 averaged 34,000 bbl/d, a 17% increase from 2006 levels, as a result of waterflood and polymer flood success and a successful primary drilling program.

Canadian Natural has 105 horizontal crude oil wells, three horizontal injection wells and six service wells planned for 2008. As a result of the positive response to polymer flooding we will be aggressively converting additional patterns to polymer flooding in other portions of the pool. New conversions will take 12 to 18 months to respond to the polymer injection which will defer production growth from Pelican Lake until 2009 or 2010. We will also continue to expand the portion of the pool amenable to primary production with the drilling of 94 primary horizontal wells.

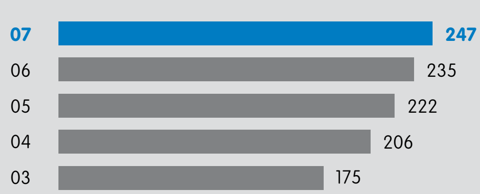
Primary Heavy Crude Oil

Located east of Edmonton and extending down and across the Alberta/Saskatchewan border, the Company has a dominant land position with 1.7 million acres, 70% of which is undeveloped. This dominance allows us to minimize capital by conducting large scale drilling and development programs. 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 12 heavy crude oil treating facilities, along with the 143 mile ECHO Pipeline, thereby reducing transportation costs and allowing us to be the only producer capable of delivering undiluted heavy oil into our blending facilities at Hardisty, Alberta.

North American successful crude oil wells drilled
(net wells)



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



2007 was another excellent year for heavy crude oil production as a result of our experienced technical team, extensive asset base and active drilling and recompletion program. During 2007 we drilled 362 low risk heavy oil net wells and recompleted approximately 626 wells to secondary zones. In 2007, heavy crude oil averaged 92,000 bbl/d.

For 2008, 311 heavy oil locations are forecast to be drilled and a further 470 net wells will be recompleted. Our defined growth plan forecasts that over 1,840 net well locations will be drilled during the next five years, keeping production relatively flat. Recovery factors for primary heavy oil are relatively low at approximately 10% and as a result we continue to pursue the development of technologies to further improve crude oil recovery. We are currently conducting research both in the field and in the laboratory and in 2008 we will initiate a pilot project whereby solvent is injected through vertical wells, contacting heavy crude oil through existing production channels. The solvent dilutes the heavy crude oil and via gravity it drains to a horizontal well and is then produced.

Thermal In-Situ Heavy Crude Oil

Canadian Natural has tremendous thermal oil sands holdings in all three oil sands deposits, namely Athabasca, Peace River and Cold Lake. Our current producing operation is our Primrose project in the Cold Lake oil sands where the majority of the heavy crude oil is produced from the Clearwater reservoir using CSS.

We have defined future plans to fully develop our Primrose assets and to develop our Athabasca properties including Kirby, Grouse, Gregoire and Birch Mountain. We have in excess of 480,000 undeveloped acres of land suitable for thermal recovery processes.

In 2007 Canadian Natural's multi-year thermal development program continued with the commencement of construction at the Primrose East Expansion project. This 40,000 bbl/d project will achieve first production in early 2009. We also continued development of the existing operations at Primrose South and North with the drilling of 11 wells. We began evaluation and field testing of several novel reservoir recovery processes to enhance recovery and improve steam usage. Our current thermal operations averaged 64,000 bbl/d for 2007.

In 2008, we plan to drill an additional 32 horizontal wells at Primrose East and complete construction of the facilities. Steam injection will commence in late 2008 with crude oil production in early 2009. We are targeting to bring on a new thermal project every 2-3 years with incremental capacity of 30,000 – 60,000 bbl/d for the foreseeable future. After the Primrose East Expansion is completed, our next expansion will be at Kirby, where we have scheduled first production for 2012.

In 2008 our thermal production will decrease slightly from 2007 for two reasons:

- We will be taking advantage of relatively lower natural gas pricing and higher crude oil pricing through steaming mature wells to capture reserves that now have robust economics.
- The cyclic production from the Primrose North Expansion peaked in late 2007 and will enter a long production phase with shallow declines in 2008.

Beyond 2009 we see the potential to add significant incremental thermal in-situ production from our oil sands leases at Kirby, Grouse, Birch Mountain, and Gregoire Lake. By executing our Defined Plan to develop these leases, we will be able to achieve 15% annual growth on our thermal production alone. We will continue to develop new technologies including geo-steering during drilling, infill drilling and steam additives to enhance recoveries. Our thermal operations represent a tremendous growth opportunity and are an integral part of Canadian Natural's Defined Plan.

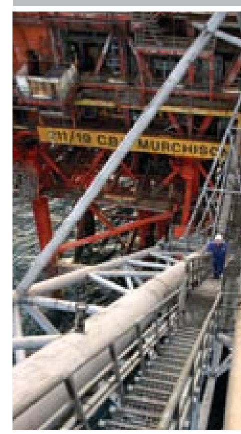
International

As a fundamental part of the Company's portfolio, our International operations provide a stable and committed source of light crude oil production. Very similar to our operations in the WCSB, we are able to apply our expertise in mature, low risk, exploitation basins to our North Sea operations. And in turn, apply what we have learned from our North Sea operations to our Offshore West Africa 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 significant resource potential in a low-risk environment. In Offshore West Africa, the Company enjoys excellent relationships with the governments of Côte d'Ivoire and Gabon, providing unmatched competitive advantage over other local operators. Providing some of the highest returning projects in the Company, the Offshore West Africa assets continue to generate significant free cash flow and provide considerable light oil growth.

United Kingdom Sector of the North Sea

By optimizing base production through efficient waterflood management, we look to increase production, lower costs and extend field life. Second stage development includes more near-pool development and exploration in order to maximize utilization of common facilities. This ultimately extends the economic life of each field. We have also paid special attention to our advanced asset integrity management program which continues to build confidence in the long term viability of our infrastructure while identifying key facility upgrades that have had a material impact on extending asset life.



During 2007, 3.7 net crude oil wells were drilled along with 3.5 net injection wells. In the northern North Sea, commissioning of the Columba E raw water injection project was successfully completed on time and on budget. Two subsea water injectors were successfully drilled allowing water injection into the reservoir. At Ninian, we saw the successful development of further infill locations, which delivered consistently. Waterflood management is critical for the long term success of Ninian and as such, water injection capacity was increased, reaching its highest injection rates since 2004. At Lyell, two subsea producing wells were drilled and brought on-stream through our newly installed production manifold. Although initial production results have been lower than originally forecast, significant initial volumes of crude oil in place has been established.

In the central North Sea, Banff provides a highly successful reservoir management strategy which delivered 20% above expectation, along with a well executed gas lift project at Kyle and excellent facility uptimes, combining to deliver the highest daily production volumes since 2004.

For 2008, four net crude oil wells are expected to be drilled in the North Sea. Improving operating efficiencies will continue to be a key focus as we balance investment with value both in the short term and our vision for the long term. Looking to longer term viability, we plan to execute four turnarounds in the year as part of our long term facilities maintenance program.

"We are leveraging our operational expertise in the North Sea into our Offshore West Africa opportunities."

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

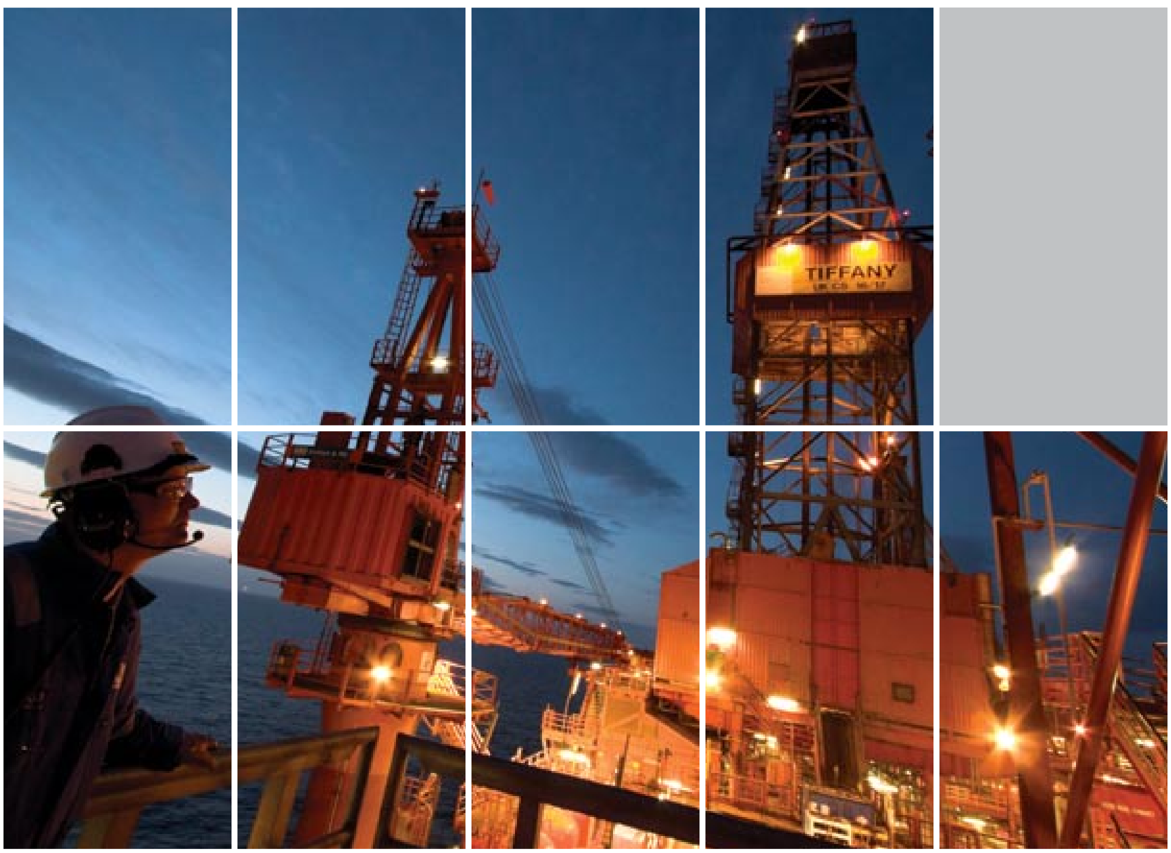
Offshore West Africa

Canadian Natural has three producing properties in Offshore West Africa, East Espoir, West Espoir and Baobab, all located in offshore Côte d'Ivoire. Canadian Natural also has the Olowi development project in offshore Gabon, where key contracts have been awarded and construction has begun. Outside of our low risk, exploitation plays, we also have an exciting exploration prospect in offshore South Africa that is in its early stages of evaluation.

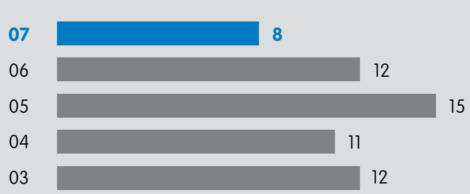
In Côte d'Ivoire in 2007, 4.1 net crude oil wells and 0.6 injection wells were drilled. Drilling continued at West Espoir on time and on budget with five producer and two injector wells successfully completed. At Baobab, we have re-engineered our topside sand control to ensure the long term integrity of the facilities and developed a solution to the down hole sand control issues we had during 2006. We have secured a deepwater rig, which we expect to mobilize during mid-2008, enabling work to begin on the restoration of the shut-in production.

At Olowi, offshore Gabon, platform construction is under way as is the FPSO conversion. Construction is under way and first oil is targeted for late 2008, increasing to a plateau rate of 20,000 bbl/d net to Canadian Natural in 2009.

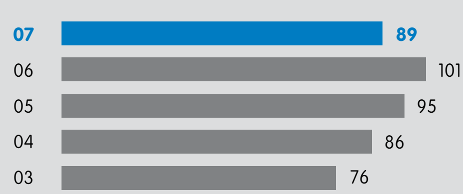
In 2008, Canadian Natural will upgrade the Espoir FPSO, adding additional gas compression, another production separator and processing upgrades. These upgrades are scheduled for completion at the end of 2009 and will increase the fluid capacity of the facility to 70,000 bbl/d, an increase of 20,000 bbl/d. At Baobab, work will begin to restore production currently shut in, with at least three of the five shut-in wells coming back on line during 2008 and 2009.



International successful crude oil wells drilled
(net wells)



International total production
(mboe/d)



Horizon Oil Sands Project

Canadian Natural holds extensive leases in the Athabasca region, just north of Fort McMurray. These lands are estimated to contain approximately 16 billion barrels of original bitumen in place. The Horizon Project represents a phased development accessing 6 billion barrels of mineable bitumen reserves and contingent resources. The Horizon Project includes a surface oil sands mining and bitumen extraction plant complimented by on-site bitumen upgrading with associated infrastructure to produce SCO. Due to the massive resource base, the mine and plant facilities are expected to produce for decades to come without production declines normally associated with crude oil production.

We are nearing completion of Phase 1 construction with first oil targeted for the third quarter of 2008. Production for Phase 1 of the project is targeted to be 110,000 bbl/d. Subsequent phases are planned with ultimate production reaching approximately 500,000 bbl/d by 2017. A 34° API, low sulphur, sweet synthetic crude is the final product.

Our technology is based on existing knowledge and equipment. We have used those technologies that are already in use at existing plants, effectively mitigating technology risk for Phase 1. That being said, our plant has been engineered to maximize benefits from the technologies. For example, the Horizon Project will have a very high level of heat sharing and integration between the facilities, reducing both natural gas consumption and GHG emission levels.

The geological risk associated with the project is very low. On our leases, over 16 stratigraphic wells per section have been drilled to identify overburden levels and determine ore composition and quality. The result is a well designed mine plan that has been optimized to support bitumen extraction and processing.

This asset has been designed to accommodate future growth. Our footprint allows for easy access to all parts of the plant and ensures that future production expansions would not impact existing operations.

Phase 1 project progress exited 2007 at 90% complete targetting first oil in the third quarter of 2008.

"The discipline we have put into this project has allowed us to remain on track for first oil in Q3 2008."

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

The construction effort itself reached 85% complete by year end and the following accomplishments were achieved:

- Only one significant contract remains to be awarded for Phase 1 – mechanical work for Sulphur Blocking;
- Commenced receipt and site assembly of Mine Operations Equipment (Shovels and Heavy Haul Trucks);
- Operations and maintenance service and supply agreements have been awarded;
- Delivered an additional 54 oversized loads to site for a total of 1,560 loads, representing approximately 94% of the total requirement. Remaining deliveries consist primarily of the balance of required Mine Operations Equipment (Shovels and Heavy Haul Trucks);
- Mine overburden removal has moved 49.9 million bank cubic meters, which represents approximately 72% of the total to be moved, and is 0.6 million bank cubic meters ahead of schedule;
- Main Control Room Distributed Control Systems equipment powered and tested;
- Commissioned 260kV Transmission line and turned over to operations;
- Commissioned Raw Water Pumphouse and turned over to operations;
- Completed reformer erection in Hydrogen Plant;
- Completed installation and pre-commissioning of CPI Separator Building;
- Completed the closure of Dyke 10 (external tailings pond) in Mining;
- Completed erection of Crushing Plants and conveyors in Ore Preparation Area;
- Completed Primary Separation Cells in Extraction; and
- Completed construction of Main Laboratory.

Preparing for First Oil

In 2008 we will continue to work towards the goal of first oil in the third quarter. Parallel to completing Phase 1 of the project, we are getting ready for operations. Our rate of operations hiring and training has gained momentum and we are nearing staffing level requirements. We remain focused on timely completion of Phase 1 while getting ready to operate the new facilities.

Teams responsible for the commissioning and start-up of the facilities have already prepared a schedule that is directly linked to the construction schedules. This allows us to identify early bottlenecks and ensure that we have adequate contingencies in place during start-up. Currently we have over 300 operations people on staff developing start up procedures, preparing training programs, recruiting additional staff, establishing maintenance programs, and operating several plant systems.

With respect to future expansions, we have determined that the Phases 2/3 execution strategy will be built out in four tranches, or four smaller projects. Tranche 1 of the Phases 2/3 expansion was completed during 2007. This tranche included a high level of front end loading with the construction of the coker foundation to accommodate a further coker drum, construction of the piperacks necessary for increased production levels, and the procurement of several long lead vessels that will be arriving on site in early 2008. The first year of spending of Tranche 2 has been approved by our Board of Directors and will run for a three year period from 2008 – 2010. Tranches 3 and 4 will be complete by 2013. Production levels are expected to be 232,000 – 250,000 bbl/d by that time period. The phased approach to future expansions breaks the project down into manageable pieces, rather than approaching it as a 'mega-project.' The development of Phase 1 gives us a distinct capital advantage for further development, along with the ability to leverage Phase 1 learnings, existing infrastructure and systems. Additionally, developing Phases 2/3 in tranches allows for minimal distraction for Phase 1 start up and optimization, and greater capital allocation flexibility as we are able to respond to commodity price fluctuations leading to a higher degree of cost control.

The Horizon Project asset is substantial and is anticipated to provide significant free cash flow in the future. Our Defined Plan is predicated upon generating the greatest value for our Shareholders.

2007 Review

Year-End Reserves
Independent Evaluation

Determination of Reserves

For the year ended December 31, 2007, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule"), and Ryder Scott Company ("Ryder Scott"), 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. Sproule evaluated the Company's North America assets and Ryder Scott evaluated its international assets. Canadian Natural has been granted an exemption from 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 additional voluntary information.

The SEC requires that oil sands mining reserves be disclosed separately from conventional oil and gas disclosure. Canadian Natural retained a qualified independent reserve 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 each of Sproule, Ryder Scott and GLJ as to the Company's reserves.

Corporate Conventional Net Reserves

Crude oil, natural gas and NGLs proved reserves increased by 1% replacing 110% of production. This was accomplished at all-in finding and on-stream cost of $14.28 per barrel of oil equivalent for proved reserves and $18.02 per barrel of oil equivalent for proved and probable reserves.

In the Evaluation Reports, 46% of crude oil and NGLs proved reserves were assigned to the proved undeveloped category, a 1 percentage point decrease from the 47% recorded in 2006.

In the Evaluation Reports, 22% 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 decreased by 1%.

North America Conventional Net Reserves

Crude oil and NGLs proved reserves increased by 4% replacing 143% of production. Natural gas proved reserves decreased by 5% replacing 63% of 2007 production and reflected the Company's decision to reduce capital spending on natural gas.

International Conventional Net Reserves

North Sea proved reserves grew by 18 million barrels to 324 million barrels of oil equivalent or 16% of the total proved Company reserves.

In Offshore West Africa proved reserves were unchanged at 139 million barrels. This is largely the result of increases in the year end crude oil price which, in the Côte d'Ivoire evaluation, accelerates project payout and increases the government royalties payable.

Horizon Oil Sands Mining Gross Lease Reserves

The gross lease proved bitumen reserves increased by 110 million barrels to 2,385 million barrels largely as a result of Tranche 2 capital spending commitments. The gross lease proved and probable bitumen reserves decreased 5 million barrels to 3,525 million barrels.

The gross lease proved synthetic crude oil reserves increased by 90 million barrels to 1,956 million barrels. The gross leased proved and probable synthetic crude oil reserves decreased 4 million barrels to 2,958 million barrels.

* Conventional crude oil, NGL and natural gas includes all of the Company's light and medium, heavy and, thermal crude oil, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets.

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

	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**

	December 31, 2006			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude oil and NGLs (mmbbl)				
North America	420	467	887	1,502
North Sea	214	85	299	422
Offshore West Africa	63	67	130	195
	697	619	1,316	2,119
Natural gas (bcf)				
North America	2,934	771	3,705	4,857
North Sea	17	20	37	93
Offshore West Africa	12	44	56	99
	2,963	835	3,798	5,049
Total reserves (mmboe)	1,191	758	1,949	2,961
Reserve replacement ratio[4] (%)			295%	472%
Cost to develop[5] ($/boe)				
10% discount	$ 1.33	$ 6.46	$ 3.32	$ 3.08
15% discount	$ 1.12	$ 5.80	$ 2.94	$ 2.66
Present value of conventional reserves[6] ($ millions)				
10% discount	$ 20,028	$ 7,469	$ 27,497	$ 37,291
15% discount	$ 17,296	$ 5,247	$ 22,543	$ 29,350

OIL SANDS MINING RESERVES [1]

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

	As of December 31, 2007		As of December 31, 2006	
	Proved Total	**Proved and Probable**	Proved Total	Proved and Probable
Gross lease reserves, before royalties (mmbbl)				
Bitumen	**2,385**	**3,525**	2,275	3,530
Synthetic crude oil[7]	**1,956**	**2,958**	1,866	2,962
Net reserves, after royalties (mmbbl)				
Bitumen	**1,995**	**2,969**	1,853	2,872
Synthetic crude oil[7]	**1,761**	**2,680**	1,596	2,542

CONVENTIONAL CRUDE OIL AND NGLS RESERVES RECONCILIATION, NET OF ROYALTIES [1]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (mmbbl)				
Reserves, December 31, 2005	694	290	134	1,118
Extensions and discoveries	53	3	–	56
Infill drilling	190	14	–	204
Improved recovery	–	12	–	12
Property purchases	26	–	–	26
Property disposals	–	–	–	–
Production	(75)	(22)	(13)	(110)
Revisions of prior estimates	(1)	2	9	10
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**
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2005	1,035	417	206	1,658
Extensions and discoveries	128	3	–	131
Infill drilling	384	17	–	401
Improved recovery	–	12	–	12
Property purchases	34	–	–	34
Property disposals	–	–	–	–
Production	(75)	(22)	(13)	(110)
Revisions of prior estimates	(4)	(5)	2	(7)
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**

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

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2005	2,741	29	72	2,842
Extensions and discoveries	250	–	–	250
Infill drilling	71	–	–	71
Improved recovery	3	–	–	3
Property purchases	1,111	–	–	1,111
Property disposals	(1)	–	–	(1)
Production	(433)	(5)	(3)	(441)
Revisions of prior estimates	(37)	13	(13)	(37)
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**
Proved and probable reserves (bcf)				
Reserves, December 31, 2005	3,548	69	110	3,727
Extensions and discoveries	307	–	–	307
Infill drilling	95	–	–	95
Improved recovery	4	–	–	4
Property purchases	1,466	–	–	1,466
Property disposals	(1)	–	–	(1)
Production	(433)	(5)	(3)	(441)
Revisions of prior estimates	(129)	29	(8)	(108)
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**

CONVENTIONAL FINDING AND ON-STREAM COSTS

	2007	2006	2005	Three Year Total
Net reserve replacement expenditures ($ millions)	**$ 3,027**	$ 8,727	$ 3,361	**$ 15,115**
Net reserve additions (mmboe) [8]				
Proved	**212**	540	251	**1,003**
Proved and probable	**168**	865	337	**1,370**
Finding and on-stream costs ($/boe) [9]				
Proved	**$ 14.28**	$ 16.16	$ 13.41	**$ 15.07**
Proved and probable	**$ 18.02**	$ 10.09	$ 9.97	**$ 11.03**

RESERVES CLASSIFICATION BY PRODUCT, NET OF ROYALTIES [(1)]

	December 31, 2007			
	Proved Developed[(2)]	**Proved Undeveloped**[(2)]	**Proved Total**[(2)]	**Proved and Probable**[(3)]
Light crude oil and NGLs				
North America	**6%**	**1%**	**7%**	**6%**
North Sea	**12%**	**3%**	**15%**	**14%**
Offshore West Africa	**4%**	**3%**	**7%**	**6%**
Total	**22%**	**7%**	**29%**	**26%**
Heavy crude oil and NGLs				
North America – Primary Heavy	**4%**	**1%**	**5%**	**5%**
North America – Pelican Lake	**4%**	**4%**	**8%**	**7%**
North America – Thermal	**7%**	**20%**	**27%**	**35%**
Total	**15%**	**25%**	**40%**	**47%**
Total crude oil and NGLs				
North America	**21%**	**26%**	**47%**	**53%**
North Sea	**12%**	**3%**	**15%**	**14%**
Offshore West Africa	**4%**	**3%**	**7%**	**6%**
Total	**37%**	**32%**	**69%**	**73%**
Natural gas				
North America	**23%**	**7%**	**30%**	**26%**
North Sea	**1%**	**0%**	**1%**	**1%**
Offshore West Africa	**0%**	**0%**	**0%**	**0%**
Total	**24%**	**7%**	**31%**	**27%**
Total Boe	**61%**	**39%**	**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)
2007	$ 62.87	$ 96.00	$ 41.70	$ 96.02
2006	$ 51.11	$ 61.05	$ 41.94	$ 58.93
2005	$ 46.12	$ 61.04	$ 32.64	$ 58.21

Natural gas	Company Average Price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	Alberta AECO C (C$/mmbtu)	British Columbia Huntingdon Sumas (C$/mmbtu)
2007	$ 6.48	$ 6.80	$ 6.52	$ 6.96
2006	$ 6.07	$ 5.52	$ 6.13	$ 6.52
2005	$ 9.45	$ 10.08	$ 9.99	$ 9.53

A foreign exchange rate of US$1.01/C$1.00 was used in the 2007 evaluation; US$0.86/C$1.00 was used in the 2006 and 2005 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 reserves using technologies implemented at the Horizon Project. The reserve values shown for bitumen and synthetic crude oil are not additive.

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

(9) 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 2008 guidance provided throughout this Management's Discussion and Analysis ("MD&A"), including the information provided in the "Outlook" section, constitutes forward-looking statements. 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.

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 assurance that the plans, initiatives or expectations upon which they are based will occur.

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 its 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 at times 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 interdependent 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 important 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 cash flow from operations, adjusted net earnings from operations and net asset value. These financial measures are not defined by Canadian generally accepted accounting principles ("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.

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, 2007. The consolidated financial statements have been prepared in accordance with Canadian GAAP. A reconciliation of Canadian GAAP to United States GAAP is included in note 17 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 exclude the effect of risk management activities and transportation and blending costs, except where otherwise noted. The following discussion and analysis refers primarily to the Company's 2007 financial results compared to 2006 and 2005, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2008.

Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2007 and its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

This MD&A is dated February 26, 2008.

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
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
FPSO	Floating Production, Storage and Offtake Vessel
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
GJ	gigajoule
Heavy Differential	Heavy crude oil differential from WTI
Horizon Project	Horizon Oil Sands Project
LLB	Lloyd Blend
mcf	thousand cubic feet
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
SCO	Synthetic light crude oil
SEC	United States Securities and Exchange Commission
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
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 the 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 central to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes that 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 its strong financial position. The Company believes that it has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising the delivery of its conventional crude oil and natural gas growth opportunities. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures program throughout the Horizon Project construction period.

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, 2007 are as follows:

- Achieved record levels of net earnings, adjusted net earnings from operations and cash flow;
- Achieved record natural gas production;
- Achieved annual production guidance for crude oil and NGLs and natural gas;
- Completed 90% of Phase 1 work progress 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)		**2007**	2006	2005
Revenue, before royalties		**$ 12,543**	$ 11,643	$ 11,130
Net earnings		**$ 2,608**	$ 2,524	$ 1,050
Per common share	– basic	**$ 4.84**	$ 4.70	$ 1.96
	– diluted	**$ 4.84**	$ 4.70	$ 1.95
Adjusted net earnings from operations (1)		**$ 2,406**	$ 1,664	$ 2,034
Per common share	– basic	**$ 4.46**	$ 3.10	$ 3.79
	– diluted	**$ 4.46**	$ 3.10	$ 3.78
Cash flow from operations (2)		**$ 6,198**	$ 4,932	$ 5,021
Per common share	– basic	**$ 11.49**	$ 9.18	$ 9.36
	– diluted	**$ 11.49**	$ 9.18	$ 9.33
Dividends declared per common share		**$ 0.34**	$ 0.30	$ 0.236
Total assets		**$ 36,114**	$ 33,160	$ 21,852
Total long-term liabilities		**$ 19,230**	$ 19,399	$ 9,790
Capital expenditures, net of dispositions		**$ 6,425**	$ 12,025	$ 4,932

(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" 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" 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)	**2007**	2006	2005
Net earnings as reported	**$ 2,608**	$ 2,524	$ 1,050
Stock-based compensation expense, net of tax (a)	**134**	95	481
Unrealized risk management loss (gain), net of tax (b)	**977**	(674)	607
Unrealized foreign exchange (gain) loss, net of tax (c)	**(449)**	114	(85)
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	**(864)**	(395)	(19)
Adjusted net earnings from operations	**$ 2,406**	$ 1,664	$ 2,034

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the 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 flowing through 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 swaps, and are immediately recognized in net earnings.

(d) All substantively 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 changes is recorded in net earnings during the period the legislation is substantively enacted. 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 Offshore West Africa. Income tax rate changes during 2005 resulted in a reduction of future income tax liabilities of approximately $19 million in North America.

CASH FLOW FROM OPERATIONS

($ millions)	**2007**	2006	2005
Net earnings	**$ 2,608**	$ 2,524	$ 1,050
Non-cash items:			
Depletion, depreciation and amortization	**2,863**	2,391	2,013
Asset retirement obligation accretion	**70**	68	69
Stock-based compensation expense	**193**	139	723
Unrealized risk management loss (gain)	**1,400**	(1,013)	925
Unrealized foreign exchange (gain) loss	**(524)**	134	(103)
Deferred petroleum revenue tax expense (recovery)	**44**	37	(9)
Future income tax (recovery) expense	**(456)**	652	353
Cash flow from operations	**$ 6,198**	$ 4,932	$ 5,021

For 2007, the Company reported net earnings of $2,608 million compared to net earnings of $2,524 million for 2006 (2005 – $1,050 million). Net earnings for the year ended December 31, 2007 included net unrealized after-tax income of $202 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2006 – net unrealized after-tax income of $860 million; 2005 – net unrealized after-tax expenses of $984 million). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2007 increased to $2,406 million from $1,664 million for 2006 (2005 – $2,034 million) primarily due to higher realized pricing, lower realized risk management losses, higher North America crude oil and NGLs and natural gas sales volumes, and lower income tax expense. These factors were partially offset by higher production expense, higher depletion, depreciation and amortization expense, higher interest expense, and the impact of the stronger Canadian dollar relative to the US dollar.

The Company expects that consolidated net earnings will continue to reflect significant volatility due to the impact of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of budgeted crude oil volumes are hedged for 2008 and approximately 53% of budgeted natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company's outstanding commodity related financial derivatives as at December 31, 2007 are detailed in the "Liquidity and Capital Resources" section of this MD&A.

As disclosed in note 2 to the Company's consolidated financial statements, commencing January 1, 2007 all derivative financial instruments are recognized at fair value on the consolidated balance sheet at each reporting date. As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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 risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007.

Due to the changes in crude oil and natural gas forward pricing and the reversal of prior-year unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007 (2006 – $1,013 million unrealized gain, $674 million after-tax; 2005 – $925 million unrealized loss, $607 million after-tax). Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales. For further details, refer to the "Risk Management Activities" section of this MD&A.

The Company also recorded a $193 million ($134 million after-tax) stock-based compensation expense as a result of the 17% increase in the Company's share price for the year ended December 31, 2007 (Company's share price as at: December 31, 2007 – $72.58; December 31, 2006 – $62.15; December 31, 2005 – $57.63; December 31, 2004 – $25.63). As required by 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 the 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 as part of the Horizon Project during the construction period. The stock-based compensation liability at December 31, 2007 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, 2007. In years when substantial share price changes occur, the Company's net 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.

Cash flow from operations for the year ended December 31, 2007 increased to $6,198 million ($11.49 per common share) from $4,932 million ($9.18 per common share) for 2006 (2005 – $5,021 million; $9.36 per common share). The increase was primarily due to higher North America crude oil and NGLs and natural gas sales volumes, higher realized pricing, and lower realized risk management losses. These factors were partially offset by higher production expense, higher interest costs, higher current taxes, and the impact of the strengthening of the Canadian dollar relative to the US dollar.

For 2007, the Company's average sales price per bbl of crude oil and NGLs increased to $55.45 per bbl from $53.65 per bbl in 2006 (2005 – $46.86 per bbl). The Company's average natural gas price increased to $6.85 per mcf from $6.72 per mcf for 2006 (2005 – $8.57 per mcf).

Total production of crude oil and NGLs before royalties decreased marginally to 331,232 bbl/d from 331,998 bbl/d for 2006 (2005 – 313,168 bbl/d). The decrease in crude oil and NGLs production primarily reflected lower production in the North Sea due to the timing of planned maintenance activities and lower production from the Baobab Field in Offshore West Africa, offset by increased production in North America including increased production from the Company's Primrose thermal projects, the results from the Pelican Lake waterflood project, and the acquisition of ACC in 2006.

Total natural gas production before royalties increased to 1,668 mmcf/d from 1,492 mmcf/d for 2006 (2005 – 1,439 mmcf/d). The increase in natural gas production primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by the production declines in 2007 due to the Company's strategic reduction in natural gas drilling activity.

Total crude oil and NGLs and natural gas production volumes before royalties increased to 609,206 boe/d from 580,724 boe/d for 2006 (2005 – 552,960 boe/d).

OPERATING HIGHLIGHTS

	2007	2006	2005
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 55.45**	$ 53.65	$ 46.86
Royalties	**5.94**	4.48	3.97
Production expense	**13.34**	12.29	11.17
Netback	**$ 36.17**	$ 36.88	$ 31.72
Natural gas ($/mcf) (1)			
Sales price (2)	**$ 6.85**	$ 6.72	$ 8.57
Royalties	**1.11**	1.29	1.75
Production expense	**0.91**	0.82	0.73
Netback	**$ 4.83**	$ 4.61	$ 6.09
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	**$ 49.05**	$ 47.92	$ 48.77
Royalties	**6.26**	5.89	6.82
Production expense	**9.75**	9.14	8.21
Netback	**$ 33.04**	$ 32.89	$ 33.74

(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)

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**
2006	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$ 11,643	$ 2,826	$ 3,108	$ 3,041	$ 2,668
Net earnings	$ 2,524	$ 313	$ 1,116	$ 1,038	$ 57
Net earnings per common share					
– basic and diluted	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11

The Company's quarterly consolidated revenues increased 20% to $3,200 million for the fourth quarter of 2007 from $2,668 million for the first quarter of 2006. Net earnings fluctuated from $57 million for the first quarter of 2006 to $798 million for the fourth quarter of 2007. Net earnings 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 financial instruments, higher depletion, depreciation and amortization charges, 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 demand growth, continued geopolitical uncertainties and fluctuations in the Heavy Differential in North America. The Company's realized crude oil and NGLs price increased to $58.03 per bbl for the fourth quarter of 2007 from $43.79 per bbl for the first quarter of 2006. The Heavy Differential averaged 38% for the fourth quarter of 2007 compared to 45% for the first quarter of 2006.

- **NATURAL GAS PRICING**
  Natural gas prices primarily reflected fluctuations in demand for natural gas and high inventory storage levels as a result of seasonality, milder overall weather experienced during 2007 and 2006, and increased liquefied natural gas imports into the US during the first half of 2007. The Company's realized natural gas price decreased to $6.28 per mcf for the fourth quarter of 2007 from $8.30 per mcf for the first quarter of 2006.

- **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, development of West and East Espoir, and additional sales volumes from the ACC acquisition completed in the fourth quarter of 2006. Total crude oil and NGLs production increased to 337,240 bbl/d for the fourth quarter of 2007 from 323,662 bbl/d for the first quarter of 2006.

- **NATURAL GAS SALES VOLUMES**
  Natural gas sales volumes primarily reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increases were partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity. Total natural gas production increased to 1,589 mmcf/d for the fourth quarter of 2007 from 1,436 mmcf/d for the first quarter of 2006.

- **FOREIGN EXCHANGE RATES**
  A general strengthening of the Canadian dollar relative to the US dollar has decreased 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 balances and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, offset by the impact of cross currency swaps. The US / Canadian dollar average exchange rate increased to US$1.0193 for the fourth quarter of 2007 from US$0.8660 for the first quarter of 2006. The US dollar / UK pound sterling average exchange rate increased to US$2.0451 for the fourth quarter of 2007 from US$1.7532 for the first quarter of 2006.

- **RISK MANAGEMENT**
  Net earnings have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market of the Company's risk management activities.

- **CHANGES IN INCOME TAX EXPENSE**
  Income tax expense and recovery fluctuations include statutory tax rate and other legislative changes enacted or substantively enacted in the various periods. Income tax rate and other legislative changes reduced future income tax liabilities by $864 million for 2007 and $395 million for 2006.

- **STOCK-BASED COMPENSATION**
  Net earnings have fluctuated due to the recognition of realized and unrealized expenses and recoveries from the mark-to-market of the Company's stock-based compensation liability. Stock-based compensation expense reflected fluctuations in the Company's share price over the eight most recently completed quarters. The Company's share price increased 26% to $72.58 per share at December 31, 2007 from $57.63 per share at December 31, 2005.

- **PRODUCTION EXPENSE**
  Production expense has fluctuated company wide primarily due to production growth and industry-wide inflationary cost pressures in all segments.

- **DEPLETION, DEPRECIATION AND AMORTIZATION**
  Depletion, depreciation and amortization expense has increased primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes.

BUSINESS ENVIRONMENT

(Yearly average)		**2007**		2006		2005
WTI benchmark price (US$/bbl)	**$**	**72.40**	$	66.25	$	56.61
Dated Brent benchmark price (US$/bbl)	**$**	**72.59**	$	65.18	$	54.45
Differential to LLB blend (US$/bbl)	**$**	**23.05**	$	21.69	$	20.83
LLB blend differential from WTI (%)		**32%**		33%		37%
Condensate benchmark price (US$/bbl)	**$**	**72.88**	$	66.24	$	57.25
NYMEX benchmark price (US$/mmbtu)	**$**	**6.92**	$	7.26	$	8.56
AECO benchmark price (C$/GJ)	**$**	**6.26**	$	6.62	$	8.05
US / Canadian dollar average exchange rate	**$**	**0.9304**	$	0.8818	$	0.8253
US / Canadian dollar year end exchange rate	**$**	**1.0120**	$	0.8581	$	0.8577

COMMODITY PRICES

Substantially all of the Company's crude oil and natural gas production is sold based directly or indirectly on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on NYMEX and AECO reference pricing. As pricing is based on US dollar benchmarks, the price the Company ultimately receives in Canadian dollars fluctuates with changes in the US / Canadian dollar exchange rate. Accordingly, 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. The average value of the Canadian dollar strengthened 6% in 2007 compared to 2006.

Increases in WTI pricing in 2007 reflected continued strong demand for crude oil and continued geopolitical events resulting in increased market uncertainty and price volatility. In December 2007, WTI averaged US$91.74 per bbl, down 8% from the record high of US$99.29 per bbl reached in November 2007. WTI averaged US$72.40 per bbl for 2007, an increase of 9% compared to US$66.25 per bbl for 2006 (2005 – US$56.61 per bbl).

Brent averaged US$72.59 per bbl for 2007, an increase of 11% compared to US$65.18 per bbl for 2006 (2005 – US$54.45 per bbl). Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which continued to benefit from strong European and Asian demand in 2007.

The Company's realized crude oil price increased from 2006 as a result of the increased WTI and Brent pricing and the narrower Heavy Differential, offset by the impact of a strengthening Canadian dollar. The Heavy Differential averaged 32% for 2007, compared to 33% for 2006 (2005 – 37%). Realized prices continued to be adversely impacted by the stronger Canadian dollar.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of geopolitical events and potential unplanned refinery outages. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$6.92 per mmbtu for 2007, a decrease of 5% from US$7.26 per mmbtu for 2006 (2005 – US$8.56 per mmbtu). AECO natural gas pricing for 2007 decreased 5% to average $6.26 per GJ from $6.62 per GJ in 2006 (2005 – $8.05 per GJ). Fluctuations in natural gas prices from 2006 were primarily related to lower overall demand resulting from the milder weather, reduced economic activity in the US, and higher liquefied natural gas imports into the US during the first half of 2007. Natural gas inventory levels in North America during 2007 continued to remain high due to stable annual production levels in the US that more than offset production declines in Canada from reduced drilling activity.

OPERATING, ROYALTY AND CAPITAL COSTS

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the North America crude oil and natural gas industry, particularly related to drilling activities and oil sands developments. The strong commodity price environment has also impacted costs in international basins, due in large part to the high demand for offshore drilling rigs.

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. 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_2 annually. In the UK, GHG regulations have been in effect since 2005. The Company has strategies in place to ensure compliance with any requirements currently in effect. The additional requirements of enacted and proposed GHG legislation will add to the cost of executing projects company wide. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

In 2007, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes 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; and
- New royalty formulas for conventional crude oil and natural gas that are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

The Company is currently awaiting finalization of the royalty implementation regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

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

($ millions)	2005	Changes due to Volumes	Changes due to Prices	Changes due to Other	2006	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2007**
North America									
Crude oil and NGLs	$ 4,317	$ 198	$ 747	$ –	$ 5,262	**$ 298**	**$ 287**	**$ –**	**$ 5,847**
Natural Gas	4,638	168	(1,002)	–	3,804	**452**	**46**	**–**	**4,302**
	8,955	366	(255)	–	9,066	**750**	**333**	**–**	**10,149**
North Sea									
Crude oil and NGLs	1,636	(168)	132	–	1,600	**(107)**	**82**	**–**	**1,575**
Natural gas	23	(4)	(3)	–	16	**(2)**	**8**	**–**	**22**
	1,659	(172)	129	–	1,616	**(109)**	**90**	**–**	**1,597**
Offshore West Africa									
Crude oil and NGLs	476	344	111	–	931	**(216)**	**36**	**–**	**751**
Natural gas	9	12	(2)	–	19	**5**	**1**	**–**	**25**
	485	356	109	–	950	**(211)**	**37**	**–**	**776**
Subtotal									
Crude oil and NGLs	6,429	374	990	–	7,793	**(25)**	**405**	**–**	**8,173**
Natural gas	4,670	176	(1,007)	–	3,839	**455**	**55**	**–**	**4,349**
	11,099	550	(17)	–	11,632	**430**	**460**	**–**	**12,522**
Midstream	77	–	–	(5)	72	**–**	**–**	**2**	**74**
Intersegment eliminations and other (1)	(46)	–	–	(15)	(61)	**–**	**–**	**8**	**(53)**
Total	$ 11,130	$ 550	$ (17)	$ (20)	$ 11,643	**$ 430**	**$ 460**	**$ 10**	**$ 12,543**

(1) Eliminates primarily internal transportation and electricity charges.

Revenue increased 8% to $12,543 million for 2007 from $11,643 million for 2006 (2005 – $11,130 million). The increase was primarily due to increased crude oil and NGLs and natural gas sales volumes in North America and increased realized crude oil and NGLs and natural gas prices company wide.

For 2007, 19% of the Company's crude oil and natural gas revenue was generated outside of North America (2006 – 22%; 2005 – 19%). North Sea accounted for 13% of crude oil and natural gas revenue for 2007 (2006 – 14%; 2005 – 15%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2007 (2006 – 8%; 2005 – 4%).

ANALYSIS OF PRODUCT PRICES

	2007	2006	2005
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 49.16**	$ 46.52	$ 39.62
North Sea	**$ 74.99**	$ 72.62	$ 66.57
Offshore West Africa	**$ 71.68**	$ 67.99	$ 59.91
Company average	**$ 55.45**	$ 53.65	$ 46.86
Natural gas ($/mcf) (1) (2)			
North America	**$ 6.87**	$ 6.77	$ 8.65
North Sea	**$ 4.26**	$ 2.66	$ 3.17
Offshore West Africa	**$ 5.68**	$ 5.37	$ 5.91
Company average	**$ 6.85**	$ 6.72	$ 8.57
Company average ($/boe) (1) (2)	**$ 49.05**	$ 47.92	$ 48.77
Percentage of gross revenue (2) (excluding midstream revenue)			
Crude oil and NGLs	**62%**	64%	54%
Natural gas	**38%**	36%	46%

(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 3% to average $55.45 per bbl for 2007 from $53.65 per bbl for 2006 (2005 – $46.86 per bbl). The increase from 2006 was due to increased benchmark crude oil prices and a slightly narrower Heavy Differential, largely offset by the impact of the stronger Canadian dollar.

The Company's realized natural gas price increased 2% to average $6.85 per mcf for 2007 from $6.72 per mcf for 2006 (2005 – $8.57 per mcf). Fluctuations in natural gas prices from 2006 were primarily related to the impact of weather and storage levels.

NORTH AMERICA

North America realized crude oil prices increased 6% to average $49.16 per bbl for 2007 from $46.52 per bbl for 2006 (2005 – $39.62 per bbl). The increase from 2006 was due to increased benchmark crude oil prices and a slightly narrower Heavy Differential, largely offset by the impact of the stronger Canadian dollar.

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 2007, the Company contributed approximately 140,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices increased slightly to average $6.87 per mcf for 2007 from $6.77 per mcf for 2006 (2005 – $8.65 per mcf), primarily related 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:

	2007	2006	2005
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	**$ 66.24**	$ 63.09	$ 58.41
Pelican Lake crude oil (C$/bbl)	**$ 46.29**	$ 45.02	$ 38.39
Primary heavy crude oil (C$/bbl)	**$ 43.77**	$ 41.35	$ 33.53
Thermal heavy crude oil (C$/bbl)	**$ 43.49**	$ 40.98	$ 32.29
Natural gas (C$/mcf)	**$ 6.87**	$ 6.77	$ 8.65

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

NORTH SEA

North Sea realized crude oil prices increased 3% to average $74.99 per bbl for 2007 from $72.62 per bbl for 2006 (2005 – $66.57 per bbl). Realized crude oil prices in the North Sea during 2007 continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the stronger Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 5% to average $71.68 per bbl for 2007 from $67.99 per bbl for 2006 (2005 – $59.91 per bbl). As all revenue in Offshore West Africa is currently recognized on a liftings basis, realized crude oil prices per barrel in any particular period are dependant on the frequency and timing of liftings of each field, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during 2007 continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the stronger Canadian dollar.

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 inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**2007**	2006	2005
North America, related to pipeline fill	**1,097,526**	1,097,526	484,157
North Sea, related to timing of liftings	**1,032,723**	910,796	747,141
Offshore West Africa, related to timing of liftings	**8,578**	113,774	412,841
	2,138,827	2,122,096	1,644,139

In 2007, net production of approximately 17,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at December 31, 2007, reducing cash flow from operations by approximately $9 million.

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2007	2006	2005
Crude oil and NGLs (bbl/d)			
North America	**246,779**	235,253	221,669
North Sea	**55,933**	60,056	68,593
Offshore West Africa	**28,520**	36,689	22,906
	331,232	331,998	313,168
Natural gas (mmcf/d)			
North America	**1,643**	1,468	1,416
North Sea	**13**	15	19
Offshore West Africa	**12**	9	4
	1,668	1,492	1,439
Total barrels of oil equivalent (boe/d)	**609,206**	580,724	552,960
Product mix			
Light/medium crude oil and NGLs	**23%**	26%	26%
Pelican Lake crude oil	**6%**	5%	4%
Primary heavy crude oil	**15%**	16%	17%
Thermal heavy crude oil	**11%**	11%	10%
Natural gas	**45%**	42%	43%

DAILY PRODUCTION, NET OF ROYALTIES

	2007	2006	2005
Crude oil and NGLs (bbl/d)			
North America	**210,769**	205,382	191,751
North Sea	**55,825**	59,940	68,487
Offshore West Africa	**26,012**	35,212	22,293
	292,606	300,534	282,531
Natural gas (mmcf/d)			
North America	**1,378**	1,185	1,125
North Sea	**13**	15	18
Offshore West Africa	**11**	9	4
	1,402	1,209	1,147
Total barrels of oil equivalent (boe/d)	**526,193**	502,024	473,742

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 of crude oil and NGLs before royalties decreased marginally to 331,232 bbl/d for 2007 from 331,998 bbl/d for 2006 (2005 – 313,168 bbl/d). The decrease in crude oil and NGLs production from 2006 primarily reflected lower production in the North Sea due to the timing of planned maintenance activities and reduced production from the Baobab Field in Offshore West Africa, offset by increased production in North America. Crude oil and NGLs production for 2007 was within the Company's guidance.

Natural gas production continues to represent the Company's largest product offering, accounting for 45% of the Company's total production. Total natural gas production before royalties increased 12% to 1,668 mmcf/d for 2007 from 1,492 mmcf/d for 2006 (2005 – 1,439 mmcf/d). The increase in natural gas production from 2006 primarily reflected additional natural gas production from the ACC acquisition, partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity. Natural gas production for 2007 was within the Company's guidance.

For 2008, annual production is forecasted to average between 316,000 and 366,000 bbl/d of crude oil and NGLs and between 1,429 and 1,513 mmcf/d of natural gas.

NORTH AMERICA

North America crude oil and NGLs production for 2007 increased 5% to average 246,779 bbl/d from 235,253 bbl/d for 2006 (2005 – 221,669 bbl/d). The increase in production from 2006 was primarily due to the results from the Pelican Lake project, the cyclic nature of the Company's thermal production, and the ACC acquisition.

North America natural gas production for 2007 increased 12% to average 1,643 mmcf/d from 1,468 mmcf/d for 2006 (2005 – 1,416 mmcf/d). The increase in natural gas production from 2006 reflected the impact of the ACC acquisition, partially offset by production declines in 2007 due to the Company's strategic decision to reduce natural gas drilling activity.

NORTH SEA

North Sea crude oil production for 2007 was 55,933 bbl/d, a decrease of 7% from 60,056 bbl/d for 2006 (2005 – 68,593 bbl/d) due to the timing of planned maintenance activities, lower than anticipated production from the Lyell Field development and water injection problems experienced during the year at the Ninian Field. The Ninian water injection issues were resolved in the fourth quarter of 2007.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production for 2007 decreased 22% to 28,520 bbl/d from 36,689 bbl/d for 2006 (2005 – 22,906 bbl/d). Production decreased from 2006 due to continued challenges with sand production at the Baobab Field where 5 of 10 production wells remain shut in. The Company has secured a deepwater rig, expected in mid-year 2008, that should enable the Company to execute its plan to return certain of the shut-in wells to production over the course of 2008 and 2009. At the Espoir Fields, production delivered in 2007 was in line with expectations, reflecting the successful execution of the drilling campaign at the West Espoir Field.

ROYALTIES

		2007		2006		2005
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**7.19**	$	5.86	$	5.37
North Sea	**$**	**0.14**	$	0.13	$	0.10
Offshore West Africa	**$**	**6.40**	$	2.81	$	1.62
Company average	**$**	**5.94**	$	4.48	$	3.97
Natural gas ($/mcf) [1]						
North America	**$**	**1.12**	$	1.31	$	1.78
North Sea	**$**	**–**	$	–	$	–
Offshore West Africa	**$**	**0.51**	$	0.22	$	0.16
Company average	**$**	**1.11**	$	1.29	$	1.75
Company average ($/boe) [1]	**$**	**6.26**	$	5.89	$	6.82
Percentage of revenue [2]						
Crude oil and NGLs		**11%**		8%		8%
Natural gas		**16%**		19%		20%
Boe		**13%**		12%		14%

(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

Crown 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 are calculated as 1% of gross revenues until the Company's capital investments in the applicable project are fully recovered, at which time the royalty increases to 25% of net profit. Effective January 1, 2009, proposed changes to the Alberta royalty regime 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.

Crude oil and NGLs royalties for 2007 continued to reflect strong realized crude oil prices and the impact of the full recovery of the Company's capital investments in the Primrose North and South Fields in 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of revenue less operating, capital and abandonment costs. North America crude oil and NGLs royalties per bbl are anticipated to average 14% to 16% of gross revenue for 2008, comparable to 15% for 2007 (2006 – 13%; 2005 – 14%).

Natural gas royalties per mcf generally fluctuate with natural gas prices and well productivity. Natural gas royalties per mcf decreased from 2006 primarily due to decreased benchmark natural gas prices and the impact of certain other adjustments. North America natural gas royalties per mcf are anticipated to average 17% to 20% of gross revenue for 2008, an increase from 16% for 2007 (2006 – 19%; 2005 – 21%).

Effective January 1, 2009, proposed new royalty formulas for conventional crude oil and natural gas are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

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 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 Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's 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 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 9% for 2007 compared to 4% for 2006 (2005 – 3%). The increase in royalty rates from 2006 was due to 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. Offshore West Africa royalty rates are anticipated to average 12% to 17% of gross revenue for 2008.

PRODUCTION EXPENSE

	2007	2006	2005
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.26**	$ 11.73	$ 10.49
North Sea	**$ 20.78**	$ 17.57	$ 14.94
Offshore West Africa	**$ 8.32**	$ 7.45	$ 6.50
Company average	**$ 13.34**	$ 12.29	$ 11.17
Natural gas ($/mcf) (1)			
North America	**$ 0.90**	$ 0.81	$ 0.71
North Sea	**$ 2.17**	$ 1.40	$ 2.44
Offshore West Africa	**$ 1.48**	$ 1.19	$ 1.05
Company average	**$ 0.91**	$ 0.82	$ 0.73
Company average ($/boe) (1)	**$ 9.75**	$ 9.14	$ 8.21

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

NORTH AMERICA

North America crude oil and NGLs production expense for 2007 increased 5% to $12.26 per bbl from $11.73 per bbl for 2006 (2005 – $10.49 per bbl). The increase in production expense from 2006 was primarily due to increased industry-wide cost pressures and a continuing upward trend in property taxes and lease rentals. During the second half of 2007, costs decreased as a result of the timing of primary steam cycles, lower cost of natural gas fuel for the Company's thermal operations, and higher production volumes in both Pelican Lake and Primrose production areas, where a large portion of costs are fixed in nature.

North America natural gas production expense for 2007 increased 11% to $0.90 per mcf from $0.81 per mcf for 2006 (2005 – $0.71 per mcf). This increase was primarily due to industry-wide cost pressures in 2006 and early 2007, a continuing upward trend in property taxes and lease rentals, as well as the Company's strategic reduction in natural gas drilling activity, decreasing natural gas sales throughout 2007 and increasing production expense per mcf on the fixed cost portion of production costs.

Production expense per boe for 2008 is anticipated to increase as a result of an overall reduction in budgeted volumes for 2008, while fixed costs, such as property taxes and lease rentals, continue to escalate.

NORTH SEA

North Sea crude oil production expense increased on a per barrel basis from 2006 due to planned maintenance shutdowns, varying production volumes on a relatively fixed cost base, the timing of liftings from various fields, and the impact of the stronger Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expense on a per barrel basis increased from 2006 primarily due to the impact of continuing operating challenges with sand production at the Baobab Field, resulting in decreased production volumes on a relatively fixed operating cost base. Production expense was positively impacted by the impact of the stronger Canadian dollar.

MIDSTREAM

($ millions)	2007	2006	2005
Revenue	**$ 74**	$ 72	$ 77
Production expense	**22**	23	24
Midstream cash flow	**52**	49	53
Depreciation	**8**	8	8
Segment earnings before taxes	**$ 44**	$ 41	$ 45

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)	2007	2006	2005
North America	**$ 2,350**	$ 1,897	$ 1,595
North Sea	**340**	297	306
Offshore West Africa	**165**	189	104
Expense	**$ 2,855**	$ 2,383	$ 2,005
$/boe	**$ 12.84**	$ 11.27	$ 10.02

(1) DD&A excludes depreciation on midstream assets.

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

Depletion, Depreciation and Amortization ("DD&A") expense for 2007 increased 20% to $2,855 million from $2,383 million for 2006 (2005 – $2,005 million). The increase in DD&A expense in total and on a boe basis in 2007 from 2006 was primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes. The increase in DD&A expense in 2007 was partially offset in the North Sea and Offshore West Africa by the impact of the stronger Canadian dollar relative to the US dollar.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) (1)	2007	2006	2005
North America	$ 38	$ 35	$ 34
North Sea	30	31	34
Offshore West Africa	2	2	1
Expense	$ 70	$ 68	$ 69
$/boe	$ 0.32	$ 0.32	$ 0.34

(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 was comparable to 2006.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (1)	2007	2006	2005
Net expense	$ 208	$ 180	$ 151
$/boe	$ 0.93	$ 0.85	$ 0.75

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

Net administration expense for 2007 increased in total and on a boe basis from 2006 primarily due to increased staffing and administrative costs and overall inflationary cost pressures.

STOCK-BASED COMPENSATION

($ millions)	2007	2006	2005
Stock-based compensation expense	$ 193	$ 139	$ 723

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 since 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 $193 million ($134 million after-tax) stock-based compensation expense during 2007 in connection with the 17% appreciation in the Company's share price (December 31, 2007 – C$72.58; December 31, 2006 – C$62.15; December 31, 2005 – C$57.63; December 31, 2004 – C$25.63). As required by GAAP, the Company's outstanding stock options are valued 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 period, 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, 2007, the Company capitalized $58 million in stock-based compensation as part of the Horizon Project (2006 – $79 million; 2005 – $101 million). The stock-based compensation liability at December 31, 2007 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, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2007, the Company paid $375 million for stock options surrendered for cash settlement (2006 – $264 million; 2005 – $227 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2007	2006	2005
Interest expense, gross	$ 632	$ 336	$ 221
Less: capitalized interest, Horizon Project	356	196	72
Interest expense, net	$ 276	$ 140	$ 149
$/boe	$ 1.24	$ 0.66	$ 0.74
Average effective interest rate	5.5%	5.7%	5.6%

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

Gross interest expense increased from 2006 primarily due to increased debt levels associated with the ACC acquisition and the on-going financing of Horizon Project capital expenditures.

The Company's average effective interest rate for 2007 reflected the impact of the stronger Canadian dollar, offset by higher cost US dollar denominated debt issued in March 2007 and the impact of higher short-term lending rates on the Company's floating rate debt due to credit market uncertainty.

In 2008, upon commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase, increasing interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

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

Commencing January 1, 2007, the Company adopted new accounting standards issued by the CICA relating to the accounting for and disclosure of financial instruments and comprehensive income.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

($ millions)	January 1, 2007
Increased current portion of other long-term assets (1)	$ 193
Decreased other long-term assets (2)	$ (16)
Decreased long-term debt (3)	$ (72)
Increased retained earnings (4)	$ 10
Increased foreign currency translation adjustment (5)	$ 13
Increased accumulated other comprehensive income (6)	$ 146
Decreased current portion of future income tax asset (7)	$ (62)
Increased future income tax liability (7)	$ 18

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.
(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.
(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.
(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.
(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.
(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.
(7) Relates to the future income tax impacts of the above noted adjustments.

Effective January 1, 2007, all derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

The Company formally documents all derivative financial instruments that are 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 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 immediately 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.

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. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

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.

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.

RISK MANAGEMENT ACTIVITIES

($ millions)	**2007**	2006	2005
Realized loss (gain)			
Crude oil and NGLs financial instruments	**$ 505**	$ 1,395	$ 753
Natural gas financial instruments	**(343)**	(70)	283
Interest rate swaps	**–**	–	(9)
	$ 162	$ 1,325	$ 1,027
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	**$ 1,244**	$ (736)	$ 847
Natural gas financial instruments	**156**	(260)	77
Interest rate and cross-currency swaps	**–**	(17)	1
	$ 1,400	$ (1,013)	$ 925
Total	**$ 1,562**	$ 312	$ 1,952

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

	2007	2006	2005
Crude oil and NGLs ($/bbl) (1)	**$ 4.18**	$ 11.57	$ 6.68
Natural gas ($/mcf) (1)	**$ (0.56)**	$ (0.13)	$ 0.54

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

Complete details related to outstanding derivative financial instruments at December 31, 2007 are disclosed in note 12 to the Company's consolidated financial statements. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 – net unrecognized liability of $990 million).

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the commodity derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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 risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007 (2006 – $1,013 million unrealized gain, $674 million after-tax; 2005 – $925 million unrealized loss, $607 million after-tax).

FOREIGN EXCHANGE

($ millions)	**2007**	2006	2005
Realized foreign exchange loss (gain)	**$ 53**	$ (12)	$ (29)
Unrealized foreign exchange (gain) loss	**(524)**	134	(103)
	$ (471)	$ 122	$ (132)

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.

The Company's Offshore West Africa foreign operations are classified as integrated for the purposes of foreign currency translation. Offshore West Africa foreign operations and foreign currency transactions and balances held in North America are directly translated into Canadian dollars using the temporal method, whereby 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. Revenue and expenses are translated to Canadian dollars at the monthly average exchange rates. All related foreign exchange gains or losses are 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 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, while production expenses in Offshore West Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the Canadian dollar to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange gain in 2007 was primarily related to the strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, partially offset by an unrealized loss of $350 million related to the impact of the cross currency swaps. The net realized foreign exchange loss for 2007 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. The Canadian dollar ended the year above parity, at US$1.0120 compared to US$0.8581 at December 31, 2006 (December 31, 2005 – US$0.8577).

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 statement of earnings.

TAXES

($ millions, except income tax rates)	**2007**	2006	2005
Taxes other than income tax			
Current	**$ 121**	$ 219	$ 203
Deferred	**44**	37	(9)
	$ 165	$ 256	$ 194
Current income tax			
North America	**$ 96**	$ 143	$ 99
North Sea	**210**	30	155
Offshore West Africa	**74**	49	32
	380	222	286
Future income tax	**(456)**	652	353
	(76)	874	639
Income tax rate and other legislative changes (1) (2) (3)	**864**	395	19
	$ 788	$ 1,269	$ 658
Effective income tax rate before income tax rate and other legislative changes	**31.1%**	37.3%	39.0%

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

(2) 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 Offshore West Africa corporate income tax rate reductions enacted in 2006.

(3) Includes the effect of a one time recovery of $19 million due to a British Columbia corporate income tax rate reduction enacted in 2005.

Taxes other than income tax primarily includes current and deferred petroleum revenue tax ("PRT"). PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including 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 a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year. In particular, current taxes in a specific year are sensitive to the timing of when the Horizon Project capital expenditures are deductible for Canadian income tax purposes.

During 2007, the Canadian Federal Government enacted or substantively enacted income tax rate and other legislative changes, resulting in a reduction of future income tax liabilities of approximately $864 million. As a result of the enacted income tax rate changes, the Canadian Federal corporate income tax rate will be reduced over the next five years from 21% in 2007 to 15% in 2012.

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 2005, enacted income tax rate changes in North America resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduced the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. As a result, in 2007 crown royalties were fully deductible and the Company is no longer eligible for the resource allowance.

The Company's consolidated effective income tax rate for 2007 was reduced primarily due to income tax rate reductions enacted in Canada during the year, the effects of the non-taxable portion of unrealized foreign exchange gains on US dollar debt, net of unrealized losses on cross currency swaps, and adjustments to future tax expense in Canada related to the final phase-in of deductibility of crown royalties and the elimination of the resource allowance deduction in 2007. For 2008, based on budgeted prices and the current availability of tax pools, the Company expects to be cash taxable in Canada in the amount of $75 million to $150 million.

NET CAPITAL EXPENDITURES [(1)]

($ millions)	**2007**	2006	2005
Expenditures on property, plant and equipment			
Net property (dispositions) acquisitions [(2)]	**$ (39)**	$ 4,733	$ (320)
Land acquisition and retention	**95**	210	254
Seismic evaluations	**124**	130	132
Well drilling, completion and equipping	**1,642**	2,340	2,000
Production and related facilities	**1,205**	1,314	1,295
Total net reserve replacement expenditures	**3,027**	8,727	3,361
Horizon Project:			
Phase 1 construction costs	**2,740**	2,768	1,249
Phases 2/3 costs	**124**	79	–
Capitalized interest, stock-based compensation and other	**437**	338	250
Total Horizon Project	**3,301**	3,185	1,499
Midstream	**6**	12	4
Abandonments [(3)]	**71**	75	46
Head office	**20**	26	22
Total net capital expenditures	**$ 6,425**	$ 12,025	$ 4,932
By segment			
North America	**$ 2,428**	$ 7,936	$ 2,530
North Sea	**439**	646	387
Offshore West Africa	**159**	134	439
Other	**1**	11	5
Horizon Project	**3,301**	3,185	1,499
Midstream	**6**	12	4
Abandonments [(3)]	**71**	75	46
Head office	**20**	26	22
Total	**$ 6,425**	$ 12,025	$ 4,932

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value.
(2) Includes Business Combinations.
(3) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core 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, 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 2007 were $6,425 million compared to $12,025 million for 2006 (2005 – $4,932 million). Excluding the ACC acquisition, net capital expenditures were $7,270 million for 2006. Capital expenditures in 2007 reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, as well as continued industry-wide inflationary pressures, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

During 2007, the Company drilled a total of 1,322 net wells consisting of 383 natural gas wells, 592 crude oil wells, 254 stratigraphic test and service wells, and 93 wells that were dry. This compared to 1,738 net wells drilled for 2006 (2005 – 1,882 net wells). The Company achieved an overall success rate of 91% for 2007, excluding the stratigraphic test and service wells (2006 – 91%; 2005 – 93%).

NORTH AMERICA

North America, including the Horizon Project, accounted for approximately 91% of the total capital expenditures for the year ended December 31, 2007 compared to approximately 93% for 2006 (2005 – 83%).

During 2007, the Company targeted 450 net natural gas wells, including 58 wells in Northeast British Columbia, 133 wells in the Northern Plains region, 110 wells in Northwest Alberta, and 149 wells in the Southern Plains region. The Company also targeted 610 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 362 primary heavy crude oil wells, 127 Pelican Lake crude oil wells, 55 thermal crude oil wells and 6 light crude oil wells were drilled. In addition, 60 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has continued to access its large crude oil drilling inventory to maximize value in both the short and long term. As a result of the Company's focus on drilling crude oil wells in 2007, natural gas drilling activities were reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory. Drilling on ACC acquired lands was optimized as part of the overall capital program.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands Assets. As part of the development, the Company is continuing to develop its Primrose thermal projects. During 2007, the Company drilled 135 stratigraphic test wells and observation wells, 2 water source wells and 55 thermal oil wells. Overall Primrose thermal production for 2007 was approximately 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, is anticipated to add approximately 40,000 bbl/d when complete. The Primrose East Expansion received Board of Directors' sanction in 2006 and the Alberta Energy and Utilities Board regulatory approval in early 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add an additional 45,000 bbl/d of production growth. 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.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout 2007. Drilling consisted of 125 horizontal crude oil wells, with plans to drill 105 additional horizontal crude oil wells in 2008. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 34,000 bbl/d in 2007 (2006 – 30,000 bbl/d).

Due to growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the Design Basis Memorandum and Engineering Design Specification of the Canadian Natural Upgrader, outside of the Horizon Project, pending clarification on the cost of future environmental legislation and a more stable cost environment.

For 2008, the Company's overall drilling activity in North America is expected to comprise approximately 314 natural gas wells and 526 crude oil wells, excluding stratigraphic and service wells.

HORIZON PROJECT

The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to commence in the third quarter of 2008 ramping up to 110,000 bbl/d of 34° API SCO.

Work progress on the Horizon Project was 90% complete at year end. The project status as at December 31, 2007 was as follows:

- Overall detailed engineering 98.5% complete and substantially complete in most areas;
- Overall procurement 99% complete with over $5.6 billion in purchase orders and contracts awarded;
- Commenced receipt and site assembly of Mine Operations equipment (Shovels and Heavy Haul Trucks);
- Overall construction progress 85% complete;
- Mine overburden removal approximately 72% complete and 0.6 million bank cubic meters ahead of schedule;
- Main Control Room Distributed Control Systems equipment powered and tested;
- Commissioned 260kV Transmission Line and turned over to operations;
- Commissioned Raw Water Pumphouse and turned over to operations;
- Completed reformer erection in Hydrogen Plant;
- Completed installation and pre-commissioning of CPI Separator Building;
- Completed the closure of Dyke 10 (external tailings pond) in Mining;
- Completed erection of Crushing Plants and conveyors in Ore Preparation Area;
- Completed Primary Separation Cells in Extraction; and
- Completed construction of Main Laboratory.

The Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

NORTH SEA

In 2007, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations, and the execution of its long-term facilities strategy. During 2007, 7.2 net wells were drilled, including 3.5 net water injectors, with an additional 1.6 net wells drilling at year end.

Commissioning of the Columba E Raw Water Injection project was successfully completed on time and on budget during 2007 and 2 water injection wells were delivered, allowing water injection into the reservoir to commence. Injection rates delivered were below expectation due to lower reservoir quality. A detailed technical evaluation has been carried out and is being executed to deliver required injection rates under sustained fracture conditions.

During 2007, the subsea project to bring gas lift to the Kyle Field was successfully completed, delivering above expectation production at the Banff / Kyle hub.

The development of the Lyell Field continued during the year with 2 production wells coming on stream through the existing infrastructure. Production from these initial Lyell wells was below expectation and future development plans are being re-evaluated as a result. The Company remains committed to unlocking the remaining development potential at the Lyell Field with a phased approach.

At the Ninian Field, the Company continued to execute its long-term facilities strategy, with investment in the Ninian South platform infrastructure in particular. In addition, infill locations were successfully developed, with production delivery from these wells in line with expectations, and water injection capacity was successfully increased.

In December 2007, the Company completed the sale of its working interest in the B-Block, comprising the Balmoral, Stirling, and Glamis Fields.

OFFSHORE WEST AFRICA

During 2007, 4.7 net wells were drilled with 0.6 wells drilling at year end.

Development drilling on West Espoir continued during 2007 with 5 additional production wells and 2 additional injector wells added. West Espoir development drilling was completed in early 2008, on budget and on time.

During 2007, the Company awarded a contract for the upgrade of the Espoir FPSO in order to increase the throughput handling capability of the vessel. Design and procurement work commenced during the year. Production volumes will not be significantly impacted during the installation work, scheduled to complete in late 2009. Gross fluids processing capacity will increase from 50,000 bbl/d to 70,000 bbl/d, with natural gas handling capacity increasing from 55 mmcf/d to 75 mmcf/d upon completion of the project.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded, and construction of the wellhead towers and the FPSO is ongoing. The project is on schedule with drilling targeted to commence in the second quarter of 2008 and first crude oil targeted in late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d, net to the Company.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**2007**	2006	2005
Working capital deficit [(1)]	**$ 1,382**	$ 832	$ 1,774
Long-term debt [(2)]	**$ 10,940**	$ 11,043	$ 3,321
Shareholders' equity			
Share capital	**$ 2,674**	$ 2,562	$ 2,442
Retained earnings	**10,575**	8,141	5,804
Accumulated other comprehensive income (loss)	**72**	(13)	(9)
Total	**$ 13,321**	$ 10,690	$ 8,237
Debt to book capitalization [(2)(3)]	**45%**	51%	29%
Debt to market capitalization [(2)(4)]	**22%**	25%	10%
After tax return on average common shareholders' equity [(5)]	**22%**	27%	14%
After tax return on average capital employed [(2)(6)]	**12%**	17%	10%

(1) Calculated as current assets less current liabilities.
(2) Long-term debt at December 31, 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs. Amounts for periods prior to January 1, 2007 were not adjusted for these items.
(3) Calculated as long-term debt; divided by the book value of common shareholders' equity plus long-term debt.
(4) Calculated as long-term debt; divided by the market value of common shareholders' equity plus long-term debt.
(5) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.
(6) 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 long-term debt for the year, including $7,001 million in average capital employed related to the Horizon Project (2006 – $3,760 million; 2005 – $1,421 million).

The Company's capital resources at December 31, 2007 consisted primarily of cash flow from operations, available 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 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. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. 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. The Company does not have any direct exposure to asset-backed commercial paper.

At December 31, 2007, the Company had undrawn bank lines of credit of $1,442 million. Details related to the Company's long-term debt at December 31, 2007 are disclosed in note 5 to the Company's audited annual consolidated financial statements. Subsequent to December 31, 2007, the Company issued an aggregate US$1,200 million of unsecured notes. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

At December 31, 2007, the Company's working capital deficit was $1,382 million and included the current portion of the stock-based compensation liability of $390 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $1,227 million. 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. 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 of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet.

Long-term debt was $10,940 million at December 31, 2007, resulting in a debt to book capitalization level of 45% as at December 31, 2007 (December 31, 2006 – 51%). While this ratio is at the high end of the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that it has the balance sheet strength and flexibility to complete Phase 1 of the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2008 at prices that protect investment returns. 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 price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of budgeted crude oil volumes are hedged for 2008 and approximately 53% of budgeted natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company has the following commodity related net financial derivatives outstanding as at December 31, 2007:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars [1]	Jan 2008 – Mar 2008	50,000 bbl/d	US$60.00 – US$80.06	WTI
	Jan 2008 – Jun 2008	25,000 bbl/d	US$60.00 – US$80.44	WTI
	Apr 2008 – Sep 2008	25,000 bbl/d	US$60.00 – US$80.46	WTI
	Jul 2008 – Sep 2008	25,000 bbl/d	US$70.00 – US$123.75	WTI
	Oct 2008 – Dec 2008	25,000 bbl/d	US$70.00 – US$112.63	WTI
	Jan 2008 – Dec 2008	20,000 bbl/d	US$50.00 – US$65.53	Mayan Heavy
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$75.22	WTI
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$76.05	WTI
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$76.98	WTI
Crude oil puts	Jan 2008 – Dec 2008	50,000 bbl/d	US$55.00	WTI
Natural gas				
AECO price collars	Jan 2008 – Mar 2008	400,000 GJ/d	C$7.00 – C$14.08	AECO
	Jan 2008 – Mar 2008	500,000 GJ/d	C$7.50 – C$10.81	AECO

(1) Subsequent to December 31, 2007, the Company entered into 25,000 bbl/d of US$70.00 – US$111.56 WTI collars for the period January to December 2009.

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

LONG-TERM DEBT

The Company's long-term debt of $10,940 million at December 31, 2007 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, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

- a $100 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 would be repayable on the maturity date.

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 in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2007.

MEDIUM-TERM NOTES

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. After issuing these securities, 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.

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

In 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

SENIOR UNSECURED NOTES

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

US DOLLAR DEBT SECURITIES

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 2007, the Company de-designated the portion of its 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 statement of earnings.

In 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the US until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

SHARE CAPITAL

As at December 31, 2007, there were 539,729,000 common shares outstanding and 30,659,000 stock options outstanding. As at February 26, 2008, the Company had 540,252,000 common shares outstanding and 29,173,000 stock options outstanding.

During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the 12-month period beginning January 24, 2007 and ending January 23, 2008 (2006 – 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million; 2005 – 850,000 common shares were purchased at an average price of $53.29 per common share for a total cost of $45 million). The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.

In February 2008, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share for 2008. The increase represents an 18% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the eighth consecutive year in which the Company has paid dividends and the seventh consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2007, an increase in the annual dividend paid by the Company was approved to $0.34 per common share for 2007. The increase represented a 13% increase from 2006.

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 debt repayments; operating leases relating to offshore FPSOs, drilling rigs and office space; and firm commitments for gathering, processing and transmission services; as well as expenditures relating to ARO. As at December 31, 2007, 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, 2007:

($ millions)	2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease [1]	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling [2] [3]	$ 267	$ 185	$ 39	$ –	$ –	$ –
Asset retirement obligations [4]	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Long-term debt [5]	$ 39	$ 2,361	$ 400	$ 395	$ 346	$ 5,098
Interest expense [6]	$ 612	$ 590	$ 487	$ 465	$ 374	$ 4,338
Office lease	$ 26	$ 28	$ 28	$ 22	$ 3	$ –
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ –	$ –

(1) Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in 2008, subject to rig availability. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 – 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$393 million have been included in this table for the period 2008 – 2010.

(4) 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 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(5) 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 $2,366 million of revolving bank credit facilities due to the extendable nature of the facilities.

(6) 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, 2007.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

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, 2007, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves [1] [3] and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from 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 reserve reconciliation 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 Annual Report. 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.

For the year ended December 31, 2007, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate 100% of Phases 1 through 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 incorporating both the mining and upgrading projects. 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, NGL and natural gas reserves.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott 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.

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

(1) Conventional crude oil, NGLs and natural gas includes all of the Company's light/medium, primary heavy, and thermal crude oil, natural gas, coal bed methane and NGLs activities. It does not include the Company's oil sands mining assets.

(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. Only future development costs and associated material well abandonment liabilities have been applied.

(3) Conventional crude oil, NGLs, and natural gas reserves, net of royalties, are estimated using royalty regulations in effect as of December 31, 2007. Similarly, bitumen and synthetic crude oil reserves, net of royalties, relating to surface mineable oil sand projects are estimated using royalty regulations in effect as of December 31, 2007. Royalty changes proposed by the Government of Alberta will be incorporated in the reserves evaluation should they be enacted.

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 synthetic crude oil. 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 insurance program to reduce risk to an acceptable level and to protect it against significant losses. 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 reviews its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risk by entering into financial derivatives with entities which are substantially all investment grade. 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:

- Using water-based, environmentally friendly drilling muds whenever possible;
- 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; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

For 2007, the Company's capital expenditures included $71 million for abandonment expenditures (2006 – $75 million; 2005 – $46 million).

The Company's estimated undiscounted ARO at December 31, 2007 was as follows:

Estimated ARO, undiscounted ($ millions)	**2007**	2006
North America	**$ 3,038**	$ 2,826
North Sea	**1,286**	1,543
Offshore West Africa	**102**	128
	4,426	4,497
North Sea PRT recovery	**(555)**	(625)
	$ 3,871	$ 3,872

The estimate of ARO is based on estimates of future costs to abandon and restore the 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 expected to result in an estimated PRT recovery of $555 million (2006 – $625 million; 2005 – $370 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 $3,871 million (2006 – $3,872 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company is concurrently 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 emission reductions 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. In the UK, GHG regulations have been in effect since 2005. The Company has strategies in place to ensure compliance with any requirements currently 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 participation of the Company and the industry 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 GAAP that have a significant impact on the financial results of the Company. Actual results could differ from those estimates, and those differences could 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 future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than constant dollar pricing as required by the SEC. 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.

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 Company retains qualified independent reserves evaluators to evaluate the Company's proved, and proved and probable crude oil and natural gas reserves. In 2007, 100% of the Company's reserves were evaluated by qualified independent reserves evaluators.

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 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 could also result in a write-down 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 6.6%. 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 capital 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 could 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 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, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

Effective January 1, 2007, the Company adopted the new accounting standards relating to the accounting for and disclosure of financial instruments. The effects of adopting these standards on the Company's opening balance sheet are discussed in further detail in the "Risk Management Activities" section of this MD&A. All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

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 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, 2007, 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 allow timely decisions regarding required disclosures.

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, 2007, 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 2007 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company believes that its disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, the Company's internal control system 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 will adopt the following three new accounting 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 section also requires the disclosure of any externally-imposed capital requirements and compliance with those requirements. The section does not define capital. The section affects disclosures only and will 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 is not anticipated to 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 will not impact the Company's accounting for financial instruments.

In addition, the following standard was issued during 2008 and will be effective for the Company's year beginning on January 1, 2009, with earlier adoption permitted:

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 capitalization of certain costs during the development and start-up of large development projects.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The CICA has confirmed that Canadian GAAP will be replaced in full with International Financial Reporting Standards as promulgated by the International Accounting Standards Board effective January 1, 2011.

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 2008 to average between 316,000 bbl/d and 366,000 bbl/d of crude oil and NGLs and between 1,429 mmcf/d and 1,513 mmcf/d of natural gas.

The forecasted capital expenditures in 2008 are currently expected to be as follows:

($ millions)		2008 Forecast
Conventional crude oil and natural gas		
North America natural gas	$	617
North America crude oil and NGLs		1,075
North Sea		231
Offshore West Africa		458
Property acquisitions, dispositions and midstream		390
	$	2,771
Horizon Project		
Phase 1 – Construction (1)	$	1,750 – 1,950
Phase 1 – Operating inventory and capital inventory		109
Phase 1 – Commissioning costs		184
Phase 2/3 – Tranche 2		439
Sustaining costs		19
Capitalized interest and other costs		381
	$	2,882 – 3,082
Total	$	5,653 – 5,853

(1) Revised forecasted capital expenditures.

NORTH AMERICA NATURAL GAS

The 2008 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)	2008 Forecast
Coal bed methane and shallow natural gas	161
Conventional natural gas	104
Cardium natural gas	14
Deep natural gas	32
Foothills natural gas	3
Total	314

The Company has reduced 2008 natural gas drilling in Alberta due to the anticipated future impact of royalty changes effective 2009.

NORTH AMERICA CRUDE OIL AND NGLS

The 2008 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)	2008 Forecast
Conventional primary heavy crude oil	311
Thermal heavy crude oil	32
Light crude oil	78
Pelican Lake crude oil	105
Total	526

HORIZON PROJECT

The Horizon Project is targeting first crude oil in the third quarter of 2008. Phase 1 construction capital is budgeted to be approximately $1.7 billion to $1.9 billion in 2008, representing a cost to completion forecast range of 25% to 28% over the original $6.8 billion estimate.

NORTH SEA

The 2008 capital forecast for the North Sea includes drilling 4 net platform wells while continuing the successful workover and recompletion program.

OFFSHORE WEST AFRICA

The 2008 capital forecast for Offshore West Africa includes re-completing 2 wells at Baobab and targeted first oil at Olowi in late 2008.

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 2007, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only; all other variables are 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	$ 96	$ 0.18	$ 70	$ 0.13
Including financial derivatives	$ 21	$ 0.04	$ 17	$ 0.03
Natural gas – AECO C$0.10/mcf [1]				
Excluding financial derivatives	$ 41	$ 0.08	$ 29	$ 0.05
Including financial derivatives	$ 33	$ 0.06	$ 23	$ 0.04
Volume changes				
Crude oil – 10,000 bbl/d	$ 132	$ 0.25	$ 70	$ 0.13
Natural gas – 10 mmcf/d	$ 16	$ 0.03	$ 6	$ 0.01
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 73 – 74	$ 0.13 – 0.14	$ 31 – 32	$ 0.06
Interest rate change – 1%	$ 38	$ 0.07	$ 38	$ 0.07

(1) For details of financial instruments in place, refer to note 12 to the Company's audited annual consolidated financial statements as at December 31, 2007.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2007	2006	2005
Crude oil and NGLs (bbl/d)							
North America	**237,489**	**240,420**	**252,095**	**256,843**	**246,779**	235,253	221,669
North Sea	**61,869**	**57,286**	**52,013**	**52,709**	**55,933**	60,056	68,593
Offshore West Africa	**27,643**	**29,788**	**28,954**	**27,688**	**28,520**	36,689	22,906
Total	**327,001**	**327,494**	**333,062**	**337,240**	**331,232**	331,998	313,168
Natural gas (mmcf/d)							
North America	**1,694**	**1,696**	**1,622**	**1,562**	**1,643**	1,468	1,416
North Sea	**15**	**15**	**10**	**13**	**13**	15	19
Offshore West Africa	**8**	**11**	**15**	**14**	**12**	9	4
Total	**1,717**	**1,722**	**1,647**	**1,589**	**1,668**	1,492	1,439
Barrels of oil equivalent (boe/d)							
North America	**519,700**	**523,037**	**522,427**	**517,101**	**520,564**	479,891	457,695
North Sea	**64,370**	**59,758**	**53,597**	**54,825**	**58,099**	62,558	71,651
Offshore West Africa	**29,044**	**31,666**	**31,460**	**29,982**	**30,543**	38,275	23,614
Total	**613,114**	**614,461**	**607,484**	**601,908**	**609,206**	580,724	552,960

PER UNIT RESULTS [1]

	Q1	Q2	Q3	Q4	2007	2006	2005
Crude oil and NGLs ($/bbl)							
Sales price [2]	$ 51.71	$ 53.74	$ 58.10	$ 58.03	$ 55.45	$ 53.65	$ 46.86
Royalties	4.92	5.46	6.65	6.66	5.94	4.48	3.97
Production expense	13.81	15.01	13.13	11.53	13.34	12.29	11.17
Netback	$ 32.98	$ 33.27	$ 38.32	$ 39.84	$ 36.17	$ 36.88	$ 31.72
Natural gas ($/mcf)							
Sales price [2]	$ 7.74	$ 7.44	$ 5.87	$ 6.28	$ 6.85	$ 6.72	$ 8.57
Royalties	1.48	1.10	0.89	0.94	1.11	1.29	1.75
Production expense	0.97	0.89	0.88	0.91	0.91	0.82	0.73
Netback	$ 5.29	$ 5.45	$ 4.10	$ 4.43	$ 4.83	$ 4.61	$ 6.09
Barrels of oil equivalent ($/boe)							
Sales price [2]	$ 49.32	$ 49.70	$ 47.96	$ 49.23	$ 49.05	$ 47.92	$ 48.77
Royalties	6.76	5.99	6.07	6.21	6.26	5.89	6.82
Production expense	10.10	10.44	9.62	8.85	9.75	9.14	8.21
Netback	$ 32.46	$ 33.27	$ 32.27	$ 34.17	$ 33.04	$ 32.89	$ 33.74

(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]	2007	2006	2005
Sales price [2]	$ 49.05	$ 47.92	$ 48.77
Royalties	6.26	5.89	6.82
Production expense [3]	9.75	9.14	8.21
Netback	33.04	32.89	33.74
Midstream contribution [3]	(0.23)	(0.23)	(0.26)
Administration	0.93	0.85	0.75
Interest, net	1.24	0.66	0.74
Realized risk management loss	0.73	6.27	5.13
Realized foreign exchange loss (gain)	0.24	(0.06)	(0.15)
Taxes other than income tax – current	0.54	1.04	1.01
Current income tax – North America	0.43	0.68	0.50
Current income tax – North Sea	0.95	0.14	0.77
Current income tax – Offshore West Africa	0.33	0.23	0.17
Cash flow	$ 27.88	$ 23.31	$ 25.08

(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	2007	2006
TSX – C$						
Trading Volume (thousands)	117,164	94,089	100,950	116,831	429,034	508,935
Share Price ($/share)						
High	$ 65.50	$ 74.99	$ 80.02	$ 79.91	$ 80.02	$ 73.91
Low	$ 52.45	$ 63.71	$ 65.43	$ 64.24	$ 52.45	$ 45.49
Close	$ 63.75	$ 70.78	$ 75.56	$ 72.58	$ 72.58	$ 62.15
Market capitalization as at December 31 ($ millions)					$ 39,174	$ 33,431
Shares outstanding (thousands)					539,729	537,903
NYSE – US$						
Trading Volume (thousands)	128,543	93,086	118,315	146,322	486,266	401,909
Share Price ($/share)						
High	$ 56.62	$ 69.97	$ 78.90	$ 87.17	$ 87.17	$ 64.38
Low	$ 44.56	$ 55.07	$ 60.70	$ 63.52	$ 44.56	$ 40.29
Close	$ 55.19	$ 66.35	$ 75.75	$ 73.14	$ 73.14	$ 53.23
Market capitalization as at December 31 ($ millions)					$ 39,476	$ 28,633
Shares outstanding (thousands)					539,729	537,903

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, 2007; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2007.

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

February 26, 2008
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 15(d)-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, 2007. 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, 2007, as stated in their Auditors' Report.

Steve W. Laut
President & Chief Operating Officer

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

February 26, 2008
Calgary, Alberta, Canada

Independent Auditors' Report

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Canadian Natural Resources Limited (the "Company") as at December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated balance sheets of the Company as at December 31, 2007 and December 31, 2006, 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, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2007 and for each of the years in the two year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. 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, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the Company's internal control over financial reporting as at December 31, 2007, 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 effectiveness of 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, 2007 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 26, 2008

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 change described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 26, 2008 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
February 26, 2008

Consolidated Balance Sheets

As at December 31

(millions of Canadian dollars)	2007	2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 21**	$ 23
Accounts receivable and other	**1,662**	1,947
Future income tax (note 8)	**480**	163
Current portion of other long-term assets (note 3)	**18**	106
	2,181	2,239
Property, plant and equipment (note 4)	**33,902**	30,767
Other long-term assets (note 3)	**31**	154
	$ 36,114	$ 33,160
LIABILITIES		
Current liabilities		
Accounts payable	**$ 379**	$ 842
Accrued liabilities	**1,567**	1,618
Current portion of other long-term liabilities (note 6)	**1,617**	611
	3,563	3,071
Long-term debt (note 5)	**10,940**	11,043
Other long-term liabilities (note 6)	**1,561**	1,393
Future income tax (note 8)	**6,729**	6,963
	22,793	22,470
SHAREHOLDERS' EQUITY		
Share capital (note 9)	**2,674**	2,562
Retained earnings	**10,575**	8,141
Accumulated other comprehensive income (loss) (note 10)	**72**	(13)
	13,321	10,690
	$ 36,114	$ 33,160

Commitments and contingencies (note 13)

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)	**2007**	2006	2005
Revenue	**$ 12,543**	$ 11,643	$ 11,130
Less: royalties	**(1,391)**	(1,245)	(1,366)
Revenue, net of royalties	**11,152**	10,398	9,764
Expenses			
Production	**2,184**	1,949	1,663
Transportation and blending	**1,570**	1,443	1,293
Depletion, depreciation and amortization	**2,863**	2,391	2,013
Asset retirement obligation accretion (note 6)	**70**	68	69
Administration	**208**	180	151
Stock-based compensation (note 6)	**193**	139	723
Interest, net	**276**	140	149
Risk management activities (note 12)	**1,562**	312	1,952
Foreign exchange (gain) loss	**(471)**	122	(132)
	8,455	6,744	7,881
Earnings before taxes	**2,697**	3,654	1,883
Taxes other than income tax (note 8)	**165**	256	194
Current income tax expense (note 8)	**380**	222	286
Future income tax (recovery) expense (note 8)	**(456)**	652	353
Net earnings	**$ 2,608**	$ 2,524	$ 1,050
Net earnings per common share (note 11)			
Basic	**$ 4.84**	$ 4.70	$ 1.96
Diluted	**$ 4.84**	$ 4.70	$ 1.95

Consolidated Statements of Shareholders' Equity

For the years ended December 31

(millions of Canadian dollars)	2007	2006	2005
Share capital			
Balance – beginning of year	**$ 2,562**	$ 2,442	$ 2,408
Issued upon exercise of stock options	**21**	21	9
Previously recognized liability on stock options exercised for common shares	**91**	101	29
Purchase of common shares under Normal Course Issuer Bid	**–**	(2)	(4)
Balance – end of year	**2,674**	2,562	2,442
Retained earnings			
Balance – beginning of year, as originally reported	**8,141**	5,804	4,922
Transition adjustment on adoption of financial instruments standards (note 2)	**10**	–	–
Balance – beginning of year, as restated	**8,151**	5,804	4,922
Net earnings	**2,608**	2,524	1,050
Dividends on common shares (note 9)	**(184)**	(161)	(127)
Purchase of common shares under Normal Course Issuer Bid	**–**	(26)	(41)
Balance – end of year	**10,575**	8,141	5,804
Accumulated other comprehensive income (loss) (note 2)			
Balance – beginning of year	**(13)**	(9)	(6)
Transition adjustment on adoption of financial instruments standards	**159**	–	–
Balance – beginning of year, after effect of transition adjustment	**146**	(9)	(6)
Other comprehensive loss, net of taxes	**(74)**	(4)	(3)
Balance – end of year	**72**	(13)	(9)
Shareholders' equity	**$ 13,321**	$ 10,690	$ 8,237

Consolidated Statements of Comprehensive Income

For the years ended December 31

(millions of Canadian dollars)	2007	2006	2005
Net earnings	**$ 2,608**	$ 2,524	$ 1,050
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income during the year, net of taxes of $6 million (2006 – $nil, 2005 – $nil)	**38**	–	–
Reclassification to net earnings, net of taxes of $45 million (2006 – $nil, 2005 – $nil)	**(96)**	–	–
	(58)	–	–
Foreign currency translation adjustment			
Translation of net investment	**(16)**	(4)	(12)
Hedge of net investment, net of taxes	**–**	–	9
	(16)	(4)	(3)
Other comprehensive loss, net of taxes	**(74)**	(4)	(3)
Comprehensive income	**$ 2,534**	$ 2,520	$ 1,047

Consolidated Statements of Cash Flows

For the years ended December 31

(millions of Canadian dollars)	2007	2006	2005
Operating activities			
Net earnings	**$ 2,608**	$ 2,524	$ 1,050
Non-cash items			
Depletion, depreciation and amortization	**2,863**	2,391	2,013
Asset retirement obligation accretion	**70**	68	69
Stock-based compensation	**193**	139	723
Unrealized risk management loss (gain)	**1,400**	(1,013)	925
Unrealized foreign exchange (gain) loss	**(524)**	134	(103)
Deferred petroleum revenue tax expense (recovery)	**44**	37	(9)
Future income tax (recovery) expense	**(456)**	652	353
Deferred charges and other	**38**	(2)	(31)
Abandonment expenditures	**(71)**	(75)	(46)
Net change in non-cash working capital (note 14)	**(346)**	(679)	(147)
	5,819	4,176	4,797
Financing activities			
(Repayment) issue of bank credit facilities, net	**(1,925)**	6,499	(435)
Issue of medium-term notes	**273**	400	400
Repayment of senior unsecured notes	**(33)**	–	(194)
Issue of US dollar debt securities	**2,553**	788	–
Repayment of preferred securities	**–**	–	(107)
Issue of common shares on exercise of stock options	**21**	21	9
Dividends on common shares	**(178)**	(153)	(121)
Purchase of common shares	**–**	(28)	(45)
Net change in non-cash working capital (note 14)	**8**	37	19
	719	7,564	(474)
Investing activities			
Expenditures on property, plant and equipment	**(6,464)**	(7,266)	(5,340)
Net proceeds on sale of property, plant and equipment	**110**	71	454
Net expenditures on property, plant and equipment	**(6,354)**	(7,195)	(4,886)
Acquisition of Anadarko Canada Corporation (note 15)	**–**	(4,641)	–
Net proceeds on sale of other assets	**–**	–	11
Net change in non-cash working capital (note 14)	**(186)**	101	542
	(6,540)	(11,735)	(4,333)
(Decrease) increase in cash and cash equivalents	**(2)**	5	(10)
Cash and cash equivalents – beginning of year	**23**	18	28
Cash and cash equivalents – end of year	**$ 21**	$ 23	$ 18

Supplemental disclosure of cash flow information (note 14)

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, 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. Each development phase ("Phase") is planned to result in incremental production capacity. 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 17.

Significant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

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

(B) MEASUREMENT UNCERTAINTY

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

Purchase price allocations, depletion, depreciation and amortization, and amounts used for impairment calculations are based on estimates of crude oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. All of the Company's reserve estimates are evaluated annually by independent engineering firms. The imprecise nature of reserves estimates makes it likely that the reserve base and the related future cash flows will be revised over time as additional data becomes available. As a result, reserve estimates are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could 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 could 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 expenses (recoveries).

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 could result in material changes to deferred amounts.

(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") by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. 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 constitutes 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 costs for mining activities 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 ready for its intended use. Costs related to major maintenance turnaround activities will be deferred 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 benefited 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 ceases once construction is substantially complete and this Phase of the Horizon Project is available for its intended use. The Company continues to capitalize a portion of interest costs related to subsequent on-going Phases of the Horizon Project.

(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 and 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. Unproved properties are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended uses. 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 located on the Horizon Project site will be amortized on the unit-of-production method based on the estimated proved and probable reserves of the Horizon Project or the productive capacity, as appropriate. 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 cash flow from the Horizon Project using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

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 statement of earnings.

(K) REVENUE RECOGNITION

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.

(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 statement 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 Government State Oil Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's 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 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 from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. Accordingly, North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

(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 and 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 as defined by the CICA Handbook: 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 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 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 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 utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

Effective January 1, 2007, all derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

The Company formally documents all derivative financial instruments that are 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 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.

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. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

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 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, 2008, the Company will adopt the following three new accounting 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 section also requires the disclosure of any externally-imposed capital requirements and compliance with those requirements. The section does not define capital. The section affects disclosures only and will 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 is not anticipated to 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 will not impact the Company's accounting for financial instruments.

In addition, the following standard was issued during 2008 and will be effective for the Company's year beginning on January 1, 2009, with earlier adoption permitted:

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 capitalization of certain costs during the development and start-up of large development projects.

(V) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2007.

2. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2007, the Company adopted the following new accounting standards issued by the CICA relating to the accounting for and disclosure of financial instruments and comprehensive income:

- Section 1530 – "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except transactions with owners. The foreign currency translation adjustment, which was previously a separate component of shareholders' equity, is now recorded as part of accumulated other comprehensive income.
- Section 3251 – "Equity" replaces Section 3250 – "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period.
- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative should be recognized on the balance sheet as well as its measurement amount.
- Section 3865 – "Hedges" replaces Accounting Guideline 13 – "Hedging Relationships" and EIC 128 – "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize all designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

		January 1, 2007
Increased current portion of other long-term assets (1)	**$**	**193**
Decreased other long-term assets (2)	**$**	**(16)**
Decreased long-term debt (3)	**$**	**(72)**
Increased retained earnings (4)	**$**	**10**
Increased foreign currency translation adjustment (5)	**$**	**13**
Increased accumulated other comprehensive income (6)	**$**	**146**
Decreased current portion of future income tax asset (7)	**$**	**(62)**
Increased future income tax liability (7)	**$**	**18**

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.
(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.
(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.
(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.
(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.
(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.
(7) Relates to the future income tax impacts of the above noted adjustments.

3. OTHER LONG-TERM ASSETS

		2007		2006
Deferred charges	**$**	**28**	$	109
Risk management (note 12)		**–**		128
Other		**21**		23
		49		260
Less: current portion		**18**		106
	$	**31**	$	154

4. PROPERTY, PLANT AND EQUIPMENT

	2007			2006		
	Cost	**Accumulated depletion and depreciation**	**Net**	Cost	Accumulated depletion and depreciation	Net
Conventional crude oil and natural gas						
North America	**$ 34,195**	**$ 12,162**	**$ 22,033**	$ 31,715	$ 9,836	$ 21,879
North Sea	**3,174**	**1,446**	**1,728**	3,370	1,341	2,029
Offshore West Africa	**1,833**	**645**	**1,188**	1,685	481	1,204
Other	**39**	**14**	**25**	38	14	24
Horizon Project	**8,651**	**–**	**8,651**	5,350	–	5,350
Midstream	**269**	**64**	**205**	263	56	207
Head office	**170**	**98**	**72**	150	76	74
	$ 48,331	**$ 14,429**	**$ 33,902**	$ 42,571	$ 11,804	$ 30,767

During the year ended December 31, 2007, the Company capitalized administrative overhead of $47 million (2006 – $41 million, 2005 – $41 million) relating to exploration and development in the North Sea and Offshore West Africa and $312 million (2006 – $255 million, 2005 – $134 million) relating primarily to the Horizon Project in North America.

During the year ended December 31, 2007, the Company capitalized $356 million (2006 – $196 million, 2005 – $72 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:

	2007	2006
Conventional crude oil and natural gas		
North America	**$ 2,259**	$ 2,244
North Sea	**10**	24
Offshore West Africa	**138**	84
Other	**25**	24
Horizon Project	**8,651**	5,350
	$ 11,083	$ 7,726

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, 2007:

	2008	2009	2010	2011	2012	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 89.61	$ 86.01	$ 84.65	$ 82.77	$ 82.26	2.0%
Hardisty Heavy 12° API (C$/bbl)	$ 54.67	$ 52.42	$ 51.56	$ 50.38	$ 50.05	2.0%
Edmonton Par (C$/bbl)	$ 88.17	$ 84.54	$ 83.16	$ 81.26	$ 80.73	2.0%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 87.61	$ 83.97	$ 82.57	$ 80.65	$ 80.10	2.0%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 7.56	$ 8.27	$ 8.74	$ 8.75	$ 8.66	2.0%
AECO (C$/mmbtu)	$ 6.51	$ 7.22	$ 7.69	$ 7.70	$ 7.61	2.3%
Huntingdon/Sumas (C$/mmbtu)	$ 6.51	$ 7.22	$ 7.69	$ 7.70	$ 7.61	2.3%

5. LONG-TERM DEBT

	2007	2006
Canadian dollar denominated debt		
Bank credit facilities		
Bankers' acceptances	**$ 4,696**	$ 6,621
Medium-term notes		
7.40% unsecured debentures repaid March 1, 2007	**–**	125
5.50% unsecured debentures due December 17, 2010	**400**	–
4.50% unsecured debentures due January 23, 2013	**400**	400
4.95% unsecured debentures due June 1, 2015	**400**	400
	5,896	7,546
US dollar denominated debt		
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2007 – US$62 million, 2006 – US$93 million)	**61**	108
US dollar debt securities		
7.80% due July 2, 2008 (2007 – US$8 million, 2006 – US$8 million)	**8**	9
6.70% due July 15, 2011 (2007 – US$400 million, 2006 – US$400 million)	**395**	466
5.45% due October 1, 2012 (2007 – US$350 million, 2006 – US$350 million)	**346**	408
4.90% due December 1, 2014 (2007 – US$350 million, 2006 – US$350 million)	**346**	408
6.00% due August 15, 2016 (2007 – US$250 million, 2006 – US$250 million)	**247**	291
5.70% due May 15, 2017 (2007 – US$1,100 million, 2006 – US$nil)	**1,087**	–
7.20% due January 15, 2032 (2007 – US$400 million, 2006 – US$400 million)	**395**	466
6.45% due June 30, 2033 (2007 – US$350 million, 2006 – US$350 million)	**346**	408
5.85% due February 1, 2035 (2007 – US$350 million, 2006 – US$350 million)	**346**	408
6.50% due February 15, 2037 (2007 – US$450 million, 2006 – US$450 million)	**445**	525
6.25% due March 15, 2038 (2007 – US$1,100 million, 2006 – US$nil)	**1,087**	–
Less – original issue discount on senior unsecured notes and US dollar debt securities(1)	**(23)**	–
	5,086	3,497
Change in fair value of interest rate swaps on US dollar debt securities(2)	**9**	–
	5,095	3,497
Long-term debt before transaction costs	**10,991**	11,043
Less – transaction costs(1) (3)	**(51)**	–
	$ 10,940	$ 11,043

(1) Effective January 1, 2007, the Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.
(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $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, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

- a $100 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 would be repayable on the maturity date.

In conjunction with the closing of the acquisition of Anadarko Canada Corporation ("ACC") in November 2006 (note 15), 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.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2007, was 5.2% (2006 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2007.

MEDIUM-TERM NOTES

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. After issuing these securities, 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.

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

In 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

SENIOR UNSECURED NOTES

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

US DOLLAR DEBT SECURITIES

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 12). 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 12). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

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 statement of earnings.

In 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million (note 12). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the US until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2008	$ 39
2009	$ 2,361
2010	$ 400
2011	$ 395
2012	$ 346
Thereafter	$ 5,098

No debt repayments are reflected for $2,366 million of revolving bank credit facilities due to the extendable nature of the facilities.

6. OTHER LONG-TERM LIABILITIES

	2007	2006
Asset retirement obligations	**$ 1,074**	$ 1,166
Stock-based compensation	**529**	744
Risk management (note 12)	**1,474**	–
Other	**101**	94
	3,178	2,004
Less: current portion	**1,617**	611
	$ 1,561	$ 1,393

ASSET RETIREMENT OBLIGATIONS

At December 31, 2007, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,426 million (2006 – $4,497 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 6.6% (2006 – 6.7%; 2005 – 6.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	2007	2006	2005
Asset retirement obligations			
Balance – beginning of year	**$ 1,166**	$ 1,112	$ 1,119
Liabilities incurred	**21**	26	47
Liabilities (disposed) acquired (note 15)	**(65)**	56	–
Liabilities settled	**(71)**	(75)	(46)
Asset retirement obligation accretion	**70**	68	69
Revision of estimates	**35**	(21)	(56)
Foreign exchange	**(82)**	–	(21)
Balance – end of year	**$ 1,074**	$ 1,166	$ 1,112

STOCK-BASED COMPENSATION

The Company recognizes a liability for the 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.

	2007	2006	2005
Stock-based compensation			
Balance – beginning of year	**$ 744**	$ 891	$ 323
Stock-based compensation	**193**	139	723
Cash payment for options surrendered	**(375)**	(264)	(227)
Transferred to common shares	**(91)**	(101)	(29)
Capitalized to Horizon Project	**58**	79	101
Balance – end of year	**529**	744	891
Less: current portion	**390**	611	629
	$ 139	$ 133	$ 262

7. EMPLOYEE FUTURE BENEFITS

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

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 5.5% (2006 – 5.0%) used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2007 was $32 million (2006 – $29 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, 2007, these plan assets had a fair value of $47 million (2006 – $54 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $10 million at December 31, 2007 (2006 – $15 million).

8. TAXES

TAXES OTHER THAN INCOME TAX

	2007	2006	2005
Current petroleum revenue tax expense	**$ 97**	$ 196	$ 181
Deferred petroleum revenue tax expense (recovery)	**44**	37	(9)
Provincial capital taxes and surcharges	**24**	23	22
	$ 165	$ 256	$ 194

INCOME TAX

The provision for income tax is as follows:

	2007	2006	2005
Current income tax – North America	**$ 96**	$ 143	$ 99
Current income tax – North Sea	**210**	30	155
Current income tax – Offshore West Africa	**74**	49	32
Current income tax expense	**380**	222	286
Future income tax (recovery) expense	**(456)**	652	353
Income tax (recovery) expense	**$ (76)**	$ 874	$ 639

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:

	2007	2006	2005
Canadian statutory income tax rate	**32.5%**	34.9%	38.0%
Income tax provision at statutory rate	**$ 877**	$ 1,275	$ 716
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	**–**	131	309
Canadian resource allowance	**–**	(129)	(293)
Deductible UK petroleum revenue tax	**(71)**	(82)	(65)
Foreign tax rate differentials	**79**	92	(1)
North America income tax rate and other legislative changes	**(864)**	(438)	(19)
UK income tax rate changes	**–**	110	–
Côte d'Ivoire income tax rate changes	**–**	(67)	–
Non-taxable portion of foreign exchange (gain) loss	**(96)**	5	(15)
Other	**(1)**	(23)	7
Income tax (recovery) expense	**$ (76)**	$ 874	$ 639

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

	2007	2006
Future income tax liabilities		
Property, plant and equipment	**$ 5,695**	$ 6,088
Timing of partnership items	**1,288**	1,394
Unrealized foreign exchange gain on long-term debt	**199**	93
Unrealized risk management activities	**–**	40
Other	**55**	13
Future income tax assets		
Asset retirement obligations	**(380)**	(487)
Loss carryforwards for income tax	**(104)**	(85)
Stock-based compensation	**(125)**	(232)
Unrealized risk management activities	**(399)**	–
Deferred petroleum revenue tax	**20**	(24)
Net future income tax liability	**6,249**	6,800
Less: current portion of future income tax asset	**(480)**	(163)
Future income tax liability	**$ 6,729**	$ 6,963

During 2007, enacted or substantively enacted income tax rate and other legislative changes resulted in a reduction of future income tax liabilities of approximately $864 million in North America. As a result of the enacted income tax rate changes, the Canadian Federal corporate income tax rate will be reduced over the next five years from 21% in 2007 to 15% in 2012.

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 2005, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in North America.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduced the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. As a result, in 2007 crown royalties were fully deductible and the Company is no longer eligible for the resource allowance.

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

	2007		2006	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**537,903**	**$ 2,562**	536,348	$ 2,442
Issued upon exercise of stock options	**1,826**	**21**	2,040	21
Previously recognized liability on stock options exercised for common shares	**–**	**91**	–	101
Purchase of common shares under Normal Course Issuer Bid	**–**	**–**	(485)	(2)
Balance – end of year	**539,729**	**$ 2,674**	537,903	$ 2,562

NORMAL COURSE ISSUER BID

During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed, for the twelve month period beginning January 24, 2007 and ending on January 23, 2008 (2006 – 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million, 2005 – 850,000 common shares were purchased at an average price of $53.29 per common share for a total cost of $45 million). The Company has not renewed the Normal Course Issuer Bid in 2008.

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 February 2008, the Board of Directors set the Company's regular quarterly dividend at $0.10 per common share (2007 – $0.085 per common share, 2006 – $0.075 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 equally 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, 2007 and 2006:

	2007		2006	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**34,431**	**$ 33.77**	30,510	$ 17.79
Granted	**7,502**	**$ 70.03**	13,090	$ 59.61
Surrendered for cash settlement	**(7,249)**	**$ 16.10**	(5,180)	$ 12.60
Exercised for common shares	**(1,826)**	**$ 11.71**	(2,040)	$ 10.67
Forfeited	**(2,199)**	**$ 46.46**	(1,949)	$ 37.51
Outstanding – end of year	**30,659**	**$ 47.23**	34,431	$ 33.77
Exercisable – end of year	**7,640**	**$ 30.00**	9,177	$ 14.73

The range of exercise prices of stock options outstanding and exercisable at December 31, 2007 were 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**
$9.63 – $9.99	935	0.06	$ 9.63	935	$ 9.63
$10.00 – $19.99	5,510	1.38	$ 15.50	2,886	$ 14.66
$20.00 – $29.99	3,946	2.32	$ 25.47	1,187	$ 25.25
$30.00 – $39.99	1,012	2.72	$ 33.25	278	$ 33.28
$40.00 – $49.99	573	4.06	$ 46.79	133	$ 45.87
$50.00 – $59.99	5,980	3.76	$ 57.99	1,168	$ 57.81
$60.00 – $69.99	5,762	4.16	$ 61.59	1,053	$ 61.75
$70.00 – $73.35	6,941	5.16	$ 70.72	–	$ –
	30,659	3.40	$ 47.23	7,640	$ 30.00

10. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	2007	2006
Derivative financial instruments designated as cash flow hedges	**$ 101**	$ –
Foreign currency translation adjustment	**(29)**	(13)
	$ 72	$ (13)

During the next twelve months, $22 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

11. NET EARNINGS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted amounts per common share:

(thousands of shares)	2007	2006	2005
Weighted average common shares outstanding – basic	**539,336**	537,339	536,650
Assumed settlement of preferred securities with common shares[1]	**–**	–	1,775
Weighted average common shares outstanding – diluted	**539,336**	537,339	538,425
Net earnings	**$ 2,608**	$ 2,524	$ 1,050
Interest on preferred securities, net of taxes[1]	**–**	–	4
Revaluation of preferred securities, net of taxes[1]	**–**	–	(2)
Diluted net earnings	**$ 2,608**	$ 2,524	$ 1,052
Net earnings per common share			
Basic	**$ 4.84**	$ 4.70	$ 1.96
Diluted	**$ 4.84**	$ 4.70	$ 1.95

(1) The preferred securities were redeemed in September 2005.

12. FINANCIAL INSTRUMENTS

RISK MANAGEMENT

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

Commencing January 1, 2007, the Company recorded all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

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

	2007	2006	
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market	Deferred revenue
Balance – beginning of year	**$ 128**	$ (877)	$ (8)
Retained earnings effect of adoption of financial instruments standards (note 2)	**14**	–	–
Net cost of outstanding put options	**58**	455	–
Net change in fair value of outstanding derivative financial instruments attributable to:			
Risk management activities	**(1,400)**	1,005	–
Interest expense	**9**	–	–
Foreign exchange	**(350)**	–	–
Other comprehensive income	**125**	–	–
Amortization of deferred revenue	**–**	–	8
	(1,416)	583	–
Add: put premium financing obligations[1]	**(58)**	(455)	–
Balance – end of year	**(1,474)**	128	–
Less: current portion	**(1,227)**	88	–
	$ (247)	$ 40	$ –

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

	2007	2006	2005
Net realized risk management loss	**$ 162**	$ 1,325	$ 1,027
Net unrealized risk management loss (gain)	**1,400**	(1,013)	925
	$ 1,562	$ 312	$ 1,952

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, risk management activities, and long-term debt. The carrying value of these financial instruments approximates their fair value, except as noted below.

	2007		2006	
(Liability) asset	**Carrying value**	**Fair value**	Carrying value	Fair value
Derivative financial instruments	**$ (1,416)**	**$ (1,416)**	$ 583	$ 805
Fixed rate notes	**$ (6,318)**	**$ (6,259)**	$ (4,410)	$ (4,434)

The estimated fair values of these financial instruments have been determined based on the Company's assessment of available market information, appropriate internal valuation methodologies and/or third party indications. However, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and the differences may be material.

COMMODITY PRICE RISK MANAGEMENT

As at December 31, 2007, the Company had the following net financial derivatives outstanding to manage its commodity price exposures:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars[1]	Jan 2008 – Mar 2008	50,000 bbl/d	US$60.00 – US$80.06	WTI
	Jan 2008 – Jun 2008	25,000 bbl/d	US$60.00 – US$80.44	WTI
	Apr 2008 – Sep 2008	25,000 bbl/d	US$60.00 – US$80.46	WTI
	Jul 2008 – Sep 2008	25,000 bbl/d	US$70.00 – US$123.75	WTI
	Oct 2008 – Dec 2008	25,000 bbl/d	US$70.00 – US$112.63	WTI
	Jan 2008 – Dec 2008	20,000 bbl/d	US$50.00 – US$65.53	Mayan Heavy
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$75.22	WTI
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$76.05	WTI
	Jan 2008 – Dec 2008	50,000 bbl/d	US$60.00 – US$76.98	WTI
Crude oil puts	Jan 2008 – Dec 2008	50,000 bbl/d	US$55.00	WTI

(1) Subsequent to December 31, 2007, the Company entered into 25,000 bbl/d of US$70.00 – US$111.56 WTI collars for the period January to December 2009.

The cost of outstanding put options of US$59 million will be settled in 2008.

	Remaining term	Volume	Weighted average price	Index
Natural gas				
AECO price collars	Jan 2008 – Mar 2008	400,000 GJ/d	C$7.00 – C$14.08	AECO
	Jan 2008 – Mar 2008	500,000 GJ/d	C$7.50 – C$10.81	AECO

Commodity related derivative financial instruments designated as hedges at December 31, 2007 were all classified as cash flow hedges.

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

As at December 31, 2007, the net pre-tax unrealized loss related to the de-designation of commodity cash flow hedges was $15 million (2006 – $41 million). This unrealized loss will be recognized in net earnings in 2008.

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 agreements 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, 2007, 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 2008 – Oct 2012	US$350	5.45%	LIBOR[1] + 0.81%
	Jan 2008 – 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, 2007 were classified as fair value hedges.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign exchange rate risk in Canada on its US dollar denominated debt and on product sales based on US dollar denominated benchmarks. The Company is also exposed to foreign exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company enters into cross currency swap agreements 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. The Company may also enter into foreign currency denominated financial contracts to manage future US dollar denominated crude oil and natural gas sales. At December 31, 2007, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency					
Swaps	Jan 2008 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2008 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2008 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency related derivative financial instruments designated as hedges at December 31, 2007 were classified as cash flow hedges.

COUNTERPARTY CREDIT RISK MANAGEMENT

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.

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 substantially all investment grade financial institutions and other entities. At December 31, 2007, the Company had net risk management assets of $20 million (December 31, 2006 – $161 million) with specific counterparties related to derivative financial instruments.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease[1]	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling[2][3]	$ 267	$ 185	$ 39	$ –	$ –	$ –
Asset retirement obligations[4]	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Office leases	$ 26	$ 28	$ 28	$ 22	$ 3	$ –
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ –	$ –

(1) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in 2008, subject to rig availability. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 – 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$393 million have been included in this table for the period 2008 – 2010.

(4) 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 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

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.

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2007	2006	2005
(Increase) decrease in non-cash working capital			
Accounts receivable and other	**$ 334**	$ (116)	$ (498)
Accounts payable	**(456)**	157	196
Accrued liabilities	**(402)**	(582)	716
Net change in non-cash working capital	**$ (524)**	$ (541)	$ 414
Relating to:			
Operating activities	**$ (346)**	$ (679)	$ (147)
Financing activities	**8**	37	19
Investing activities	**(186)**	101	542
	$ (524)	$ (541)	$ 414

Other cash flow information:	2007	2006	2005
Interest paid	**$ 556**	$ 262	$ 200
Taxes paid	**$ 418**	$ 703	$ 430

15. 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 currency forward contracts designated as hedges of the ACC purchase price.

16. SEGMENTED INFORMATION

The Company's conventional crude oil and natural gas activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities relate to 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 included in the segmented information as other.

Inter-segment eliminations include internal transportation and electricity charges.

	Conventional Crude Oil and Natural Gas								
	North America			North Sea			Offshore West Africa		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Segmented revenue	**$ 10,149**	$ 9,066	$ 8,955	**$ 1,597**	$ 1,616	$ 1,659	**$ 776**	$ 950	$ 485
Less: royalties	**(1,318)**	(1,203)	(1,350)	**(3)**	(3)	(3)	**(70)**	(39)	(13)
Revenue, net of royalties	**8,831**	7,863	7,605	**1,594**	1,613	1,656	**706**	911	472
Segmented expenses									
Production	**1,642**	1,436	1,211	**432**	390	379	**94**	106	53
Transportation and blending	**1,595**	1,465	1,310	**16**	15	20	**1**	1	–
Depletion, depreciation and amortization	**2,350**	1,897	1,595	**340**	297	306	**165**	189	104
Asset retirement obligation accretion	**38**	35	34	**30**	31	34	**2**	2	1
Realized risk management activities	**129**	1,022	870	**33**	303	157	**–**	–	–
Total segmented expenses	**5,754**	5,855	5,020	**851**	1,036	896	**262**	298	158
Segmented earnings before the following	**$ 3,077**	$ 2,008	$ 2,585	**$ 743**	$ 577	$ 760	**$ 444**	$ 613	$ 314
Non-segmented expenses									
Administration									
Stock-based compensation									
Interest, net									
Unrealized risk management activities									
Foreign exchange (gain) loss									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax expense									
Future income tax (recovery) expense									
Net earnings									

CAPITAL EXPENDITURES

	2007			2006		
	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	**$ 2,428**	**$ 52**	**$ 2,480**	$ 7,936	$ 1,521	$ 9,457
North Sea	**439**	**(77)**	**362**	646	(14)	632
Offshore West Africa	**159**	**(11)**	**148**	134	1	135
Other	**1**	**–**	**1**	11	–	11
	3,027	**(36)**	**2,991**	8,727	1,508	10,235
Horizon Project[2]	**3,301**	**–**	**3,301**	3,185	–	3,185
Midstream	**6**	**–**	**6**	12	–	12
Head office	**20**	**–**	**20**	26	–	26
	$ 6,354	**$ (36)**	**$ 6,318**	$ 11,950	$ 1,508	$ 13,458

(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 and stock-based compensation.

	Midstream			Inter-segment elimination and other			Total		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
	$ 74	$ 72	$ 77	**$ (53)**	$ (61)	$ (46)	**$ 12,543**	$ 11,643	$ 11,130
	–	–	–	**–**	–	–	**(1,391)**	(1,245)	(1,366)
	74	72	77	**(53)**	(61)	(46)	**11,152**	10,398	9,764
	22	23	24	**(6)**	(6)	(4)	**2,184**	1,949	1,663
	–	–	–	**(42)**	(38)	(37)	**1,570**	1,443	1,293
	8	8	8	**–**	–	–	**2,863**	2,391	2,013
	–	–	–	**–**	–	–	**70**	68	69
	–	–	–	**–**	–	–	**162**	1,325	1,027
	30	31	32	**(48)**	(44)	(41)	**6,849**	7,176	6,065
	$ 44	$ 41	$ 45	**$ (5)**	$ (17)	$ (5)	**4,303**	3,222	3,699
							208	180	151
							193	139	723
							276	140	149
							1,400	(1,013)	925
							(471)	122	(132)
							1,606	(432)	1,816
							2,697	3,654	1,883
							165	256	194
							380	222	286
							(456)	652	353
							$ 2,608	$ 2,524	$ 1,050

SEGMENTED ASSETS

	2007	2006
Conventional crude oil and natural gas		
North America	**$ 23,617**	$ 23,670
North Sea	**1,957**	2,248
Offshore West Africa	**1,354**	1,323
Other	**41**	46
Horizon Project	**8,740**	5,444
Midstream	**333**	355
Head office	**72**	74
	$ 36,114	$ 33,160

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

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

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

(millions of Canadian dollars, except per common share amounts)	Notes	**2007**	2006	2005
Net earnings – Canadian GAAP		**$ 2,608**	$ 2,524	$ 1,050
Adjustments				
Depletion,				
net of taxes of $1 million (2006 – $1 million, 2005 – $3 million)	(A,D)	**(10)**	2	4
Stock-based compensation,				
net of taxes of $3 million (2006 – $18 million, 2005 – $nil)	(B)	**(22)**	(40)	–
Future income taxes	(H)	**(234)**	–	–
Derivative financial instruments and hedging activities,				
net of taxes of $nil (2006 – $15 million, 2005 – $11 million)	(C,D)	**–**	117	(19)
Net earnings before cumulative effect of change in accounting policy – US GAAP		**2,342**	2,603	1,035
Cumulative effect of change in accounting policy,				
net of taxes of $nil (2006 – $3 million, 2005 – $nil)	(B)	**–**	(8)	–
Net earnings – US GAAP		**$ 2,342**	$ 2,595	$ 1,035
Net earnings before cumulative effect of change in accounting policy – US GAAP per common share				
Basic		**$ 4.34**	$ 4.84	$ 1.93
Diluted	(F)	**$ 4.32**	$ 4.77	$ 1.88
Net earnings – US GAAP per common share				
Basic		**$ 4.34**	$ 4.83	$ 1.93
Diluted	(F)	**$ 4.32**	$ 4.75	$ 1.88

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	**2007**	2006	2005
Comprehensive income – Canadian GAAP		**$ 2,534**	$ 2,520	$ 1,047
US GAAP earnings adjustments		**(266)**	71	(15)
Derivative financial instruments and hedging activities,				
net of taxes of $nil (2006 – $394 million; 2005 – $312 million)	(C,D)	**–**	805	(635)
Comprehensive income – US GAAP		**$ 2,268**	$ 3,396	$ 397

The components of accumulated other comprehensive income under US GAAP, net of taxes, would be as follows:

	2007	2006
Derivative financial instruments designated as cash flow hedges	**$ 101**	$ 159
Foreign currency translation adjustment	**(29)**	(13)
Accumulated other comprehensive income	**$ 72**	$ 146

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

			2007	
(millions of Canadian dollars)	Notes	**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	(I)	**31**	**51**	**82**
		$ 36,114	**$ 142**	**$ 36,256**
Current liabilities	(B)	**$ 3,563**	**$ 66**	**$ 3,629**
Long-term debt	(I)	**10,940**	**51**	**10,991**
Other long-term liabilities	(B)	**1,561**	**20**	**1,581**
Future income tax	(A,B,D,E,H)	**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**

(millions of Canadian dollars)	Notes	2006 Canadian GAAP	2006 Increase (Decrease)	2006 US GAAP
Current assets	(C)	$ 2,239	$ 131	$ 2,370
Property, plant and equipment	(A,B,D,E)	30,767	89	30,856
Other long-term assets	(C)	154	29	183
		$ 33,160	$ 249	$ 33,409
Current liabilities	(B)	$ 3,071	$ 30	$ 3,101
Long-term debt	(C)	11,043	(26)	11,017
Other long-term liabilities	(B)	1,393	20	1,413
Future income tax	(A,B,C,D,E)	6,963	21	6,984
Share capital		2,562	–	2,562
Retained earnings		8,141	45	8,186
Accumulated other comprehensive (loss) income	(C)	(13)	159	146
		$ 33,160	$ 249	$ 33,409

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"). 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 prior years resulted in the recognition of a ceiling test impairment under US GAAP, decreasing property, plant and equipment.

For the year ended December 31, 2007, US GAAP net earnings would have decreased by $4 million (2006 – increased by $3 million, 2005 – increased by $4 million), net of income taxes of $8 million (2006 – $2 million, 2005 – $3 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, 2007, US GAAP net earnings would have decreased by $22 million (2006 – $48 million), net of income taxes of $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. There was no difference from Canadian GAAP prior to 2006.

(C) Effective January 1, 2007, the Company adopted new accounting standards for financial instruments as described in note 2. 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, for the year ended December 31, 2006, assets would have increased by $160 million, liabilities would have decreased by $9 million, and accumulated other comprehensive income would have increased by $159 million as a result of recording all derivative financial instruments at fair value in accordance with US GAAP.

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 (2005 – loss of $19 million, net of income taxes of $11 million).

(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, 2007, US GAAP net earnings would have been decreased by $6 million (2006 – $1 million), net of income taxes of $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, 2007, an additional 3,376,000 shares would have been included in the calculation of diluted earnings per share for US GAAP (2006 – 8,762,000 additional shares, 2005 – 13,593,000 additional shares).

(G) In July 2006, the FASB issued Interpretation ("FIN") No. 48 "Accounting for Uncertainty in Tax Positions – an Interpretation of FASB Statement No. 109", effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes thresholds for recognizing the benefits of uncertain tax positions in the financial statements. It also provides guidance on derecognition, classification, interest and penalties, disclosure and transition. The adoption of this standard did not result in a reconciling item under US GAAP.

(H) 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 results in a difference in timing of the recognition of a $234 million future tax recovery.

(I) 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 $51 million of debt issue costs from long-term debt to deferred charges in 2007. There was no difference from Canadian GAAP prior to 2007.

(J) **US GAAP – Recently issued accounting standards**

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 Company is currently assessing the impact this standard has on its consolidated financial statements.

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 Company is currently assessing the impact this standard has on its consolidated financial statements.

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.

Supplementary Oil & Gas Information
(unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States FAS 69, "Disclosures about Oil and Gas Producing Activities", and where applicable is reconciled to the US GAAP financial information.

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 years ended December 31, 2007, 2006, 2005 and 2004 the reports by Sproule Associates Limited 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 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, 2007, 2006, 2005 and 2004:

Crude oil and NGLs (mmbbl)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2004	648	303	115	1,066
Extensions and discoveries	98	–	–	98
Improved recovery	3	3	2	8
Purchases of reserves in place	–	–	15	15
Sales of reserves in place	(3)	–	–	(3)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	18	9	10	37
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)	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	**66**	**28**	**8**	**102**
Reserves, December 31, 2007	**920**	**310**	**128**	**1,358**
Net proved developed reserves				
December 31, 2004	367	218	20	605
December 31, 2005	402	214	80	696
December 31, 2006	420	214	63	697
December 31, 2007	**426**	**240**	**70**	**736**

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2004	2,591	27	72	2,690
Extensions and discoveries	506	–	–	506
Improved recovery	30	–	–	30
Purchases of reserves in place	6	–	–	6
Sales of reserves in place	(23)	–	–	(23)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	42	9	1	52
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	(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	**41**	**46**	**12**	**99**
Reserves, December 31, 2007	**3,521**	**81**	**64**	**3,666**
Net proved developed reserves				
December 31, 2004	2,213	12	5	2,230
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**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

			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

			2005		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 20,886	$ 2,675	$ 1,365	$ 14	$ 24,940
Unproved properties	1,372	28	182	13	1,595
	22,258	2,703	1,547	27	26,535
Less: accumulated depletion and depreciation	(7,993)	(1,022)	(294)	(14)	(9,323)
Net capitalized costs	$ 14,265	$ 1,681	$ 1,253	$ 13	$ 17,212

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

			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

			2005		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ (448)	$ (3)	$ 63	$ –	$ (388)
Unproved	210	–	(52)	–	158
Exploration	360	22	16	5	403
Development	2,386	232	439	–	3,057
Costs incurred	$ 2,508	$ 251	$ 466	$ 5	$ 3,230

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, 2007, 2006 and 2005 are summarized in the following tables:

			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**

			2006	
(millions of Canadian dollars)	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

(millions of Canadian dollars)		North America		North Sea		Offshore West Africa		Total
		2005						
Crude oil and natural gas revenue, net of royalties and blending costs	$	5,727	$	1,499	$	472	$	7,698
Production		(1,211)		(379)		(53)		(1,643)
Transportation		(287)		(20)		–		(307)
Depletion, depreciation and amortization		(1,588)		(306)		(104)		(1,998)
Asset retirement obligation accretion		(34)		(34)		(1)		(69)
Petroleum revenue tax		–		(172)		–		(172)
Income tax		(1,007)		(235)		(110)		(1,352)
Results of operations	$	1,600	$	353	$	204	$	2,157

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

(millions of Canadian dollars)		North America		North Sea		Offshore West Africa		Total
		2006						
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

(millions of Canadian dollars)	2005 North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 52,266	$ 19,961	$ 8,515	$ 80,742
Future production costs	(17,310)	(6,130)	(1,803)	(25,243)
Future development and asset retirement obligations	(3,916)	(3,099)	(1,032)	(8,047)
Future income taxes	(10,272)	(6,631)	(2,092)	(18,995)
Future net cash flows	20,768	4,101	3,588	28,457
10% annual discount for timing of future cash flows	(7,793)	(1,144)	(1,068)	(10,005)
Standardized measure of future net cash flows	$ 12,975	$ 2,957	$ 2,520	$ 18,452

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)	**2007**	2006	2005
Sales of crude oil and natural gas produced, net of production costs	**$ (7,150)**	$ (5,635)	$ (5,785)
Net changes in sales prices and production costs	**7,412**	(2,420)	11,056
Extensions, discoveries and improved recovery	**1,429**	4,769	3,596
Changes in estimated future development costs	**(169)**	(1,885)	(971)
Purchases of proved reserves in place	**39**	2,406	469
Sales of proved reserves in place	**(103)**	(2)	(130)
Revisions of previous reserve estimates	**2,380**	81	961
Accretion of discount	**2,760**	3,112	1,812
Changes in production timing and other	**508**	(2,156)	1,414
Net change in income taxes	**(3,378)**	1,270	(4,458)
Net change	**3,728**	(460)	7,964
Balance – beginning of year	**17,992**	18,452	10,488
Balance – end of year	**$ 21,720**	$ 17,992	$ 18,452

Ten-Year Review

Years ended December 31	**2007**	2006	2005	2004	2003	2002	2001	2000	1999	1998
FINANCIAL INFORMATION [1]										
(Cdn $ millions, except per share amounts)										
Net earnings	**2,608**	2,524	1,050	1,405	1,403	539	639	758	213	31
Per share – basic	**$ 4.84**	$ 4.70	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$ 0.51	$ 0.08
Cash flow from operations [2]	**6,198**	4,932	5,021	3,769	3,160	2,254	1,920	1,884	724	444
Per share – basic	**$ 11.49**	$ 9.18	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$ 1.74	$ 1.12
Capital expenditures, net of dispositions (including business combinations)	**6,425**	12,025	4,932	4,633	2,506	4,069	1,885	2,823	1,901	610
Balance sheet information										
Working capital (deficiency) surplus	**(1,382)**	(832)	(1,774)	(652)	(505)	(14)	(6)	(77)	36	58
Property, plant and equipment, net	**33,902**	30,767	19,694	17,064	13,714	12,934	8,766	7,439	4,679	3,135
Total assets	**36,114**	33,160	21,852	18,372	14,643	13,793	9,290	8,051	4,976	3,329
Long-term debt	**10,940**	11,043	3,321	3,538	2,748	4,200	2,788	2,573	2,157	1,426
Shareholders' equity	**13,321**	10,690	8,237	7,324	6,006	4,754	3,928	3,297	1,962	1,317
SHARE INFORMATION [1]										
Common shares outstanding (thousands)	**539,729**	537,903	536,348	536,361	534,926	535,104	484,804	489,116	445,816	399,236
Weighted average shares outstanding (thousands)	**539,336**	537,339	536,650	536,223	536,940	511,532	485,200	466,804	415,624	397,324
Dividends declared per common share	**$ 0.34**	$ 0.30	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ –	$ –	$ –
Trading statistics [1]										
TSX – C$										
Trading volume (thousands)	**429,034**	508,935	637,992	606,024	590,702	619,316	534,976	567,412	430,460	410,440
Share Price ($/share)										
High	**$ 80.02**	$ 73.91	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$ 9.65	$ 7.88
Low	**$ 52.45**	$ 45.49	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$ 4.95	$ 4.56
Close	**$ 72.58**	$ 62.15	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$ 8.81	$ 5.75
NYSE – US$										
Trading volume (thousands)	**486,266**	401,909	251,554	125,468	46,916	31,864	20,764	3,172	–	–
Share Price ($/share)										
High	**$ 87.17**	$ 64.38	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$ –	$ –
Low	**$ 44.56**	$ 40.29	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$ –	$ –
Close	**$ 73.14**	$ 53.23	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$ –	$ –
RATIOS										
Debt to book capitalization [3]	**45%**	51%	29%	34%	33%	47%	42%	44%	52%	52%
Return on average common shareholders' equity, after tax [3]	**22%**	27%	14%	21%	26%	13%	18%	29%	13%	2%
Daily production before royalties per ten thousand common shares (boe/d)	**11.3**	10.8	10.3	9.6	8.5	8.2	7.4	6.6	5.0	4.7
Conventional proved and probable reserves per common share (boe) [4]	**6.3**	6.4	4.8	4.3	4.0	3.3	3.1	2.9	2.4	1.9
Net asset value per common share [1][5]	**$ 68.93**	$ 56.41	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54	$ 12.33	$ 8.08

(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 and 2007, $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	**2007**	2006	2005	2004	2003	2002	2001	2000	1999	1998
OPERATING INFORMATION										
Conventional crude oil and NGLs (mmbbl, constant prices and costs)										
Company gross proved reserves (before royalties)										
North America	**1,084**	1,043	785	695	672	665	644	643	554	284
North Sea	**311**	299	290	303	222	203	83	102	–	–
Offshore West Africa	**148**	145	148	125	106	94	61	36	–	–
	1,543	1,487	1,223	1,123	1,000	962	788	781	554	284
Company gross proved and probable reserves (before royalties)										
North America	**1,806**	1,753	1,154	992	977	742	740	731	640	380
North Sea	**406**	421	417	415	317	277	106	134	–	–
Offshore West Africa	**218**	223	230	214	187	162	111	46	–	–
	2,430	2,397	1,801	1,621	1,481	1,181	957	911	640	380
Conventional natural gas (bcf, constant prices and costs)										
Company gross proved reserves (before royalties)										
North America	**4,275**	4,507	3,378	3,202	3,006	3,048	2,566	2,360	2,183	1,901
North Sea	**81**	37	29	27	62	71	94	91	–	–
Offshore West Africa	**79**	69	83	81	86	90	69	65	–	–
	4,435	4,613	3,490	3,310	3,154	3,209	2,729	2,516	2,183	1,901
Company gross proved and probable reserves (before royalties)										
North America	**5,582**	5,898	4,372	4,100	3,611	3,450	2,915	2,762	2,547	2,211
North Sea	**113**	93	69	57	101	89	118	114	–	–
Offshore West Africa	**109**	121	127	102	111	120	96	84	–	–
	5,804	6,112	4,568	4,259	3,823	3,659	3,129	2,960	2,547	2,211
Total proved reserves (before royalties) (mmboe)	**2,282**	2,256	1,804	1,674	1,526	1,497	1,243	1,200	918	601
Total proved and probable reserves (before royalties) (mmboe)	**3,397**	3,416	2,562	2,330	2,118	1,791	1,479	1,404	1,065	749
Oil sands, mining (mmbbl, constant prices and costs)										
Gross lease proved and probable reserves (before royalties)										
Bitumen	**3,525**	3,530	3,430	–	–	–	–	–	–	–
Synthetic crude oil [1]	**2,958**	2,962	2,878	–	–	–	–	–	–	–
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America	**247**	235	222	206	175	169	167	155	87	76
North Sea	**56**	60	68	65	57	39	36	17	–	–
Offshore West Africa	**28**	37	23	12	10	7	3	2	–	–
	331	332	313	283	242	215	206	174	87	76
Natural gas (mmcf/d)										
North America	**1,643**	1,468	1,416	1,330	1,245	1,204	906	793	721	673
North Sea	**13**	15	19	50	46	27	12	1	–	–
Offshore West Africa	**12**	9	4	8	8	1	–	–	–	–
	1,668	1,492	1,439	1,388	1,299	1,232	918	794	721	673
Total production (before royalties) (mboe/d)	**609**	581	553	514	459	421	359	306	207	188
Product pricing										
Average crude oil and NGLs price ($/bbl)	**55.45**	53.65	46.86	37.99	32.66	31.22	23.45	31.89	22.26	11.98
Average natural gas price ($/mcf)	**6.85**	6.72	8.57	6.50	6.21	3.77	5.45	4.92	2.52	2.11

(1) SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

Corporate Information

Board of Directors

***Catherine M. Best** (1 – Chair) (2)
Executive Vice-President, Risk Management & Chief Financial Officer,
Calgary Health Region 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 (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.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)
Chairman, Calgary Health Region
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

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

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

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeffrey 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 & Managing Director
CNR International

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

*Determined to be independent by the Nominating and Corporate Governance Committee and the Board of Directors and pursuant to the independence standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

CORPORATE OFFICES

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Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

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Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Ryder Scott Company
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

STOCK LISTING

CNQ

Toronto Stock Exchange
New York Stock Exchange

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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 US companies listed on the NYSE.

Toronto Stock Exchange ("TSX") rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans and material revisions to such plans. Canadian Natural follows TSX rules with respect to shareholder approval of equity compensation plans.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2007 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying the quality of its public disclosure.

Canadian Natural

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