Canadian Natural

The Premium Value, Defined Growth, Independent.

Annual Report 2006

Discipline

Opportunity

Strategy

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
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
CNUG	Canadian Natural Upgrader
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalents
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse Gas
Horizon Project	Horizon Oil Sands Project
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
OGIP	Original Gas In Place
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 42 for the complete special note regarding forward-looking statements.

All production and sales statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Methodologies for determining annual reserves are described on pages 37 to 41.

This report also includes references to financial measures commonly used in the oil and gas industry that are not defined by Generally Accepted Accounting Principles ("GAAP"). The Company uses these measures to evaluate its performance, however they should not be considered an alternative to or more meaningful than net earnings.

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 subdivisions of the common shares that occurred in May 2004 and May 2005, shows the aggregate amount of the cash dividends declared per common share in each of its last three years ended December 31.

	2006	2005	2004
Cash dividends declared per common share	$ 0.300	$ 0.236	$ 0.200

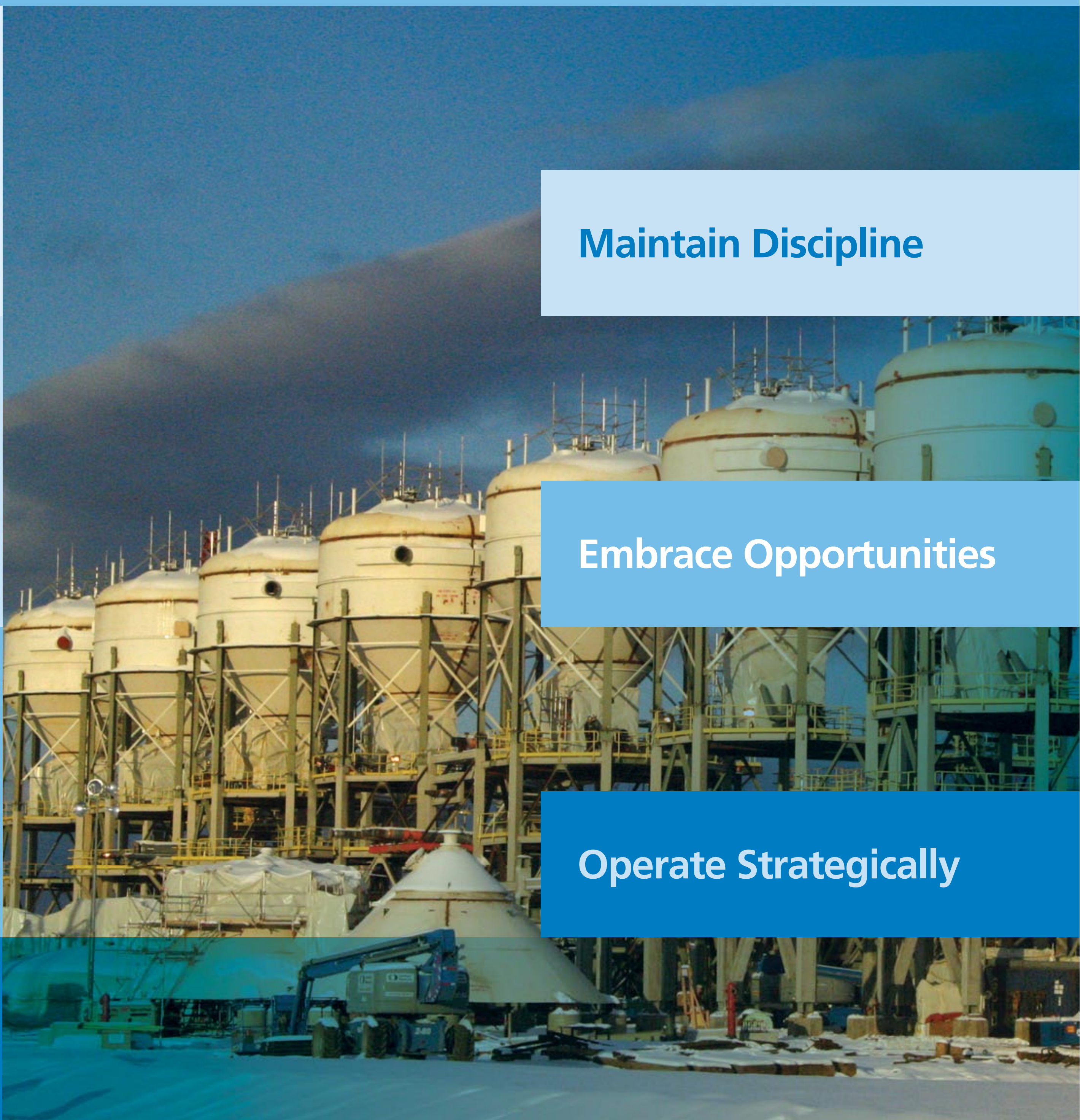
NOTICE OF ANNUAL MEETING

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 3, 2007 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

Our business strategy is solid and proven. Our teams continue to demonstrate discipline in a challenging environment, capitalizing on opportunities as they arise.



Maintain Discipline

Embrace Opportunities

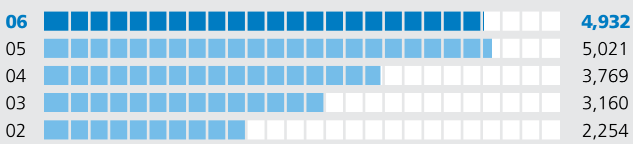
Operate Strategically

Highlights

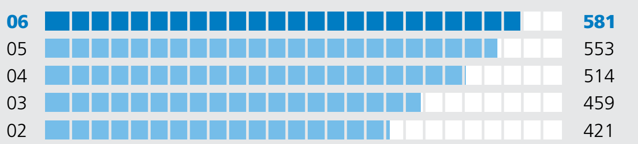
	2006	2005	2004
FINANCIAL ($ millions, except per share data)			
Revenue, before royalties	**$ 11,643**	$ 11,130	$ 8,269
Net earnings	**$ 2,524**	$ 1,050	$ 1,405
Per common share – basic (1)	**$ 4.70**	$ 1.96	$ 2.62
– diluted (1)	**$ 4.70**	$ 1.95	$ 2.60
Adjusted net earnings from operations (2)	**$ 1,664**	$ 2,034	$ 1,405
Per common share – basic (1)	**$ 3.10**	$ 3.79	$ 2.62
– diluted (1)	**$ 3.10**	$ 3.78	$ 2.60
Cash flow from operations (2)	**$ 4,932**	$ 5,021	$ 3,769
Per common share – basic (1)	**$ 9.18**	$ 9.36	$ 7.03
– diluted (1)	**$ 9.18**	$ 9.33	$ 6.98
Capital expenditures, net of dispositions	**$ 12,025**	$ 4,932	$ 4,633
Long-term debt	**$ 11,043**	$ 3,321	$ 3,538
Shareholders' equity	**$ 10,690**	$ 8,237	$ 7,324
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (mbbl/d)			
North America	**235**	222	206
North Sea	**60**	68	65
Offshore West Africa	**37**	23	12
	332	313	283
Natural gas (mmcf/d)			
North America	**1,468**	1,416	1,330
North Sea	**15**	19	50
Offshore West Africa	**9**	4	8
	1,492	1,439	1,388
Barrels of oil equivalent (mboe/d)	**581**	553	514

(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.
(2) Adjusted net earnings from operations and cash flow from operations are non-GAAP terms that represent net earnings adjusted for certain items of a non-operational and non-cash nature. 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)



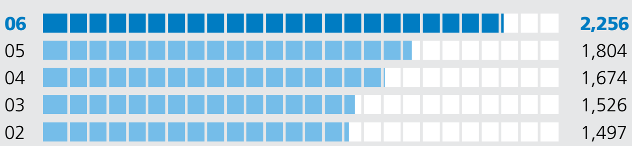
Total production, before royalties (mboe/d)



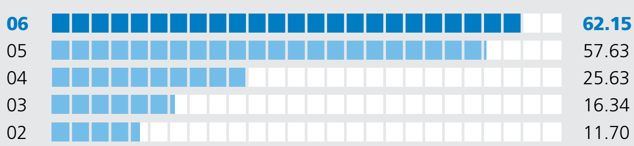
Drilling activity (net wells, excluding stratigraphic test/service wells)	**2006**	2005	2004
North America	**1,351**	1,617	1,099
North Sea	**8**	13	11
Offshore West Africa	**4**	4	3
	1,363	1,634	1,113
Core undeveloped landholdings (thousands of net acres)			
North America	**12,785**	10,947	11,523
North Sea	**299**	352	565
Offshore West Africa	**207**	426	886
Company gross proved reserves (before royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**1,043**	785	695
North Sea	**299**	290	303
Offshore West Africa	**145**	148	125
	1,487	1,223	1,123
Conventional natural gas (bcf)			
North America	**4,507**	3,378	3,202
North Sea	**37**	29	27
Offshore West Africa	**69**	83	81
	4,613	3,490	3,310
Barrels of oil equivalent (mmboe)	**2,256**	1,804	1,674
Net proved reserves (after royalties)			
Conventional crude oil and NGLs (mmbbl)			
North America	**887**	694	648
North Sea	**299**	290	303
Offshore West Africa	**130**	134	115
	1,316	1,118	1,066
Conventional natural gas (bcf)			
North America	**3,705**	2,741	2,591
North Sea	**37**	29	27
Offshore West Africa	**56**	72	72
	3,798	2,842	2,690
Barrels of oil equivalent (mmboe)	**1,949**	1,592	1,514
Net oil sands proved mineable reserves (after royalties)			
Bitumen (mmbbl)	**1,853**	1,848	–
Synthetic crude oil* (mmbbl)	**1,596**	1,626	–

* 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 (mmboe)



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



Letter to Shareholders

ALLAN P. MARKIN,
CHAIRMAN OF THE BOARD

N. MURRAY EDWARDS,
VICE-CHAIRMAN OF THE BOARD

For Canadian Natural, 2006 was a year of both challenges and tremendous opportunities. Higher commodity prices were accompanied by significant cost inflation throughout each of our basins, meaning that we had to be even more vigilant ensuring full cycle economics were maintained. Challenge, however, often leads to opportunities as well – and 2006 presented a compelling opportunity to acquire Anadarko Canada Corporation ("ACC"). We were well positioned to seize upon this opportunity, in the process adding tremendous upside potential into our natural gas project portfolio.

STRATEGIES AND THE BUSINESS ENVIRONMENT

Commodity prices remained strong, but volatile, during 2006 with both natural gas and crude oil pricing dropping during the second half of the year due to a combination of buildup of product inventories and reduced political and weather risk.

However, the robust price environment of the past two years has resulted in significant cost inflation throughout all of our basins. In particular, for our Western Canadian natural gas business, the cost increases have been excessive. High demand has resulted in increased pricing – but this was coupled with inefficiencies to create a very unfavorable cost environment for organic growth. Efficiency of many service crews were low due to a lack of trained personnel. This was combined with an unusually warm start to the 2005/6 winter drilling season and the resultant aggressive attempts by industry to complete drilling programs prior to the end of the winter operating season. The result was some of the highest finding and development costs in history for the natural gas industry in Canada.

We responded by optimizing our capital allocation to only the highest return on capital projects. We significantly cut natural gas spending and shifted capital into heavy crude oil drilling.

While we control an extensive asset base of heavy crude oil properties, available markets have historically precluded a large ramp up production. Our heavy crude oil marketing plan has sought 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. During 2006, Canadian Natural and industry had major success in this regard through two pipeline reversals expanding capacity into the Cushing hub and, importantly for Canadian Natural, to the US Gulf Coast as we have committed capacity on this line for a period of 5 years. As a result of these developments the market for Canadian heavy crude oil greatly expanded. As a consequence, our heavy crude oil discount to light crude oil migrated towards the higher priced Mayan heavy benchmark crude.

While we experienced heavy crude oil differentials of 41% of the WTI benchmark price entering 2006, by April 2006 it had reduced to 28% and averaged 29% over the last nine months of the year. These reduced differentials coupled with a more controllable cost environment in heavy oil development results in exceptionally strong economics and a re-emphasis on this type of activity in 2006 and 2007.

Canadian Natural's strategy allows us to allocate capital to maximize returns and remains predicated on:

- Maintaining a large project portfolio in every basin we operate to enable 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, but remain focused on low cost exploitation.
- Identifying and completing opportunistic major acquisitions.
- Controlling costs through area knowledge and domination of core focus regions.

NORTH AMERICAN NATURAL GAS – MAINTAINING DISCIPLINE / CAPTURING OPPORTUNITY

We remain a significant producer of natural gas in Canada, representing approximately 10% of western Canadian output. Further, our undeveloped land base represents the largest portfolio in the industry - meaning that we have exposure to virtually every play type found in the basin. Natural gas remains our largest single product sold at about 42% of our production mix in 2006, similar to the 43% recorded in 2005.

The challenges for organic growth of natural gas were articulated earlier. In our view, the cost structure erodes gas economics considerably when compared to that achieved for heavy oil.

We were one of the first in the industry to address the effects of this inflation through reallocation of capital from natural gas into heavy

JOHN G. LANGILLE,
VICE-CHAIRMAN OF THE BOARD

STEVE W. LAUT,
PRESIDENT &
CHIEF OPERATING OFFICER

oil during the second quarter of last year. This activity reduction was expanded throughout 2006 and carries into 2007. For example, while we drilled 975 natural gas wells in 2005, we had reduced that to 732 in 2006 with a further reduction to 423 planned for 2007.

Challenges to industry often create opportunity and during the second half of 2006 we were able to seize upon the ability to acquire ACC. It was our confidence in our ability to deliver the Horizon Project coupled with our strong balance sheet that enabled us to complete this transaction.

We consider the ACC assets to be high quality, long life properties with significant upside beyond the proved reserves – in fact, it may prove to be the most significant natural gas acquisition in our history. The assets provide exposure to a variety of play types and greatly complement our existing asset base. In addition to significant production and undeveloped land, a vast infrastructure and processing capacity will benefit both our heritage properties and new developments. We believe ACC's proved reserves were acquired at an attractive price, particularly given the costs of organic growth in the basin; and, in the process we have significantly increased our project portfolio available to drive future organic growth.

Integration of people and assets is now complete and we are looking forward to developing our expanded and exceptional portfolio of natural gas opportunities. The majority of the ACC team has been retained, further bolstering our own depth. We look forward to working together with each of these team members over the coming years as we maximize the value of the expanded asset base. Already, our five and ten year drilling programs are reflecting alternatives to maximizing the development plan of our expanded project portfolio.

NORTH AMERICAN CRUDE OIL – DISCIPLINED USE OF TECHNOLOGY TO CREATE VALUE

Success in our Canadian crude oil operations continued with production increasing 6% over 2005 levels and heavy crude oil pricing reaching record levels during the year. We remain the leading producer of heavy crude oil in Canada and with large amounts of original oil in place identified on our lands, we are in position to continue to grow this production.

At Pelican Lake our waterflood and polymer flood enhanced oil recovery ("EOR") schemes are adding significant reserves at low cost following a disciplined approach to optimizing results. We evaluated and tested alternative processes over the past three years and are now in the process of fully implementing our findings with the result that proved and probable net reserves at Pelican Lake increased by 97 million barrels of oil equivalent during 2006. We believe that our approach of piloting technologies in small areas of the pool afforded us the greatest flexibility to try different approaches without risking damage to the reservoir. We now believe that the waterflood / polymer flood EOR is the optimal solution for the majority of the reservoir. Further, we are actively looking for other pools in which we can leverage this knowledge.

On our conventional heavy crude oil properties we have procured the services of two fully dedicated slant drilling rigs to complete our programs over the next 3.5 years. By committing to this service for an extended term we can better control efficiencies and ensure that well trained crews are available to us.

At our thermal in-situ projects, Primrose North continues to outperform our expectations with production having increased by 19% in 2006 over 2005. Future developments are also underway with the 40,000 barrel per day Primrose East targeted for first oil in 2009 and plans for the 30,000 barrel per day Kirby in-situ development with first oil forecast in the first half of the next decade. Resource delineation drilling continues on each of these properties along with Birch Mountain and Gregoire Lake.

Here again, we continue to evaluate technologies to maximize resource potential. For example, use of geo-steering technologies for drilling of horizontal thermal wells allows us to better control and place the drill bit. This in turn expands an economically drillable resource. Examination of producing reservoirs has also expanded our knowledge of reservoir management. For example, we now believe that we can improve recovery factors on our Primrose property through narrowed well spacing and use of various follow up processes.

In all, we have identified ten separate increments of in-situ developments which will seek to access our vast heavy oil resource potential over the next several years.

To this end we continue to pursue our three pronged marketing strategy such that market price risk does not impair our ability to develop this portfolio. The first two elements of this strategy were previously discussed and have shown remarkable success. The third element of this strategy is the continued development of conversion capacity for heavy crude oil. To this end we reviewed the merits of building an additional upgrader outside of the Horizon Project to eliminate market risks on the majority of our planned in-situ developments. While such a plan would over time maximize the value of our heavy crude oil properties for shareholders, there is growing uncertainty relating to increased environmental costs for upgraders located in Canada and inflationary capital cost pressures. Based upon the results of the Scoping Study, which identified 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 DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

INTERNATIONAL OPERATIONS – DISCIPLINED MANAGEMENT OF COSTS TO DRIVE CASH FLOW

Our International operations represented a significant portion of 2006 growth with increases in Offshore West Africa being partially offset by lower volumes in the North Sea. In 2007 the emphasis on our international assets is focused on cost control in order to maximize cash flows. However, selective growth initiatives are underway in both basins.

Average light crude oil production in the North Sea decreased by about 8,500 barrels per day or 12% from the previous year, primarily the result of expanded maintenance activities. We continue to execute our strategy in the North Sea through exploitation beyond the optimization of existing facilities and waterfloods into more near pool developments and exploration such as the ongoing development at the Columba Terraces and the Lyell Field. This maximizes utilization of the common facilities and ultimately extends all fields' economic lives.

Our Offshore West Africa crude oil production volumes from Côte d'Ivoire increased by 60% to about 36,700 barrels per day. This improvement reflected better than planned production from the East Espoir development as well as a full year of production from the deep water Baobab Field and the commencement of production from the West Espoir satellite development late in the year.

The year was not without its challenges, however, as sanding issues experienced at the Baobab field expanded - with the result that 5 of 10 producer wells were shut in by the end of 2006, leaving approximately 15,500 barrels per day of production off-line. While mitigation plans have been identified they are reliant upon the procurement of a deep water rig. To date we have not been able to secure these services due to high industry demand.

We expect continued growth in Offshore West Africa where the Olowi Field located offshore Gabon received local government approvals in 2006 and Board of Director sanction for development in November 2006. Development plans include a floating production, storage and offtake vessel ("FPSO"), handling production from four shallow water wellhead towers. First oil is currently targeted for late 2008, with an anticipated plateau of 20,000 barrels per day.

HORIZON OIL SANDS PROJECT – DISCIPLINED EXECUTION OF OUR PROJECT STRATEGY

Phase 1 of this bitumen mining and integrated upgrader project made significant progress during the year, entering 2006 at 19% complete and exiting 57% complete. The Horizon Oil Sands Project ("Horizon Project") benefited from a disciplined process 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. This high degree of cost certainty was augmented by an expanded hedging program which ensured that adequate free cash flow to complete the four year construction effort would be available. While there was a cost associated with the hedging program, it was the combination of these two elements which enabled Canadian Natural to retain a 100% working interest in the Horizon Project without having to compromise on any of our conventional developments.

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. Further, this high project definition reduces the risks associated with late engineering or "scope" changes which have historically resulted in significant cost revisions for oil sands builders. Finally, 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 our fly in/fly out capability from our on-site air strip. Today, workers from all across Canada regularly fly on one of 55 flights per week, direct to our site and home again, on various shifts which accommodate their lifestyles.

PROGRESS ON OUR FOUR PERFORMANCE INDICATORS

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

06	**9.18**
05	9.36
04	7.03
03	5.88
02	4.41

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

06	**10.8**
05	10.3
04	9.6
03	8.5
02	8.2

With the Horizon Project 57% complete at the end of 2006 and targeted to achieve approximately 90% completion at the end of 2007, at this time we continue to expect final costs not materially different than our original $6.8 billion target cost with an on-schedule commissioning in the third quarter of 2008. While there are still numerous challenges and inflationary pressures, our teams have performed very well, again highlighting a cultural focus on project execution.

We are targeting to have revised cost estimates for Phases 2 and 3 development in mid 2008. By that time we will better understand the impacts of cost and service inflation as well as the prospects for higher than planned commodity pricing. We are driven to ensure that full cycle economics of the prospect are not impaired and as such will consider various alternatives to the development, financing and timing of the project. Beyond this, future phases of development are realistic extensions of the plan, ultimately targeting for daily production of approximately 500,000 barrels per day of light synthetic crude oil from the leases. In total, we estimate resource potential of 6 billion barrels of mineable bitumen at the Horizon Project.

FINANCIAL STRENGTH – A CORE ELEMENT OF OUR BUSINESS STRATEGY

We continue to believe in strong fiscal management. In particular, we have a very strong hedge program underpinning our 2007 cash flows and this, combined with better than expected heavy crude oil differentials and continued operating and capital discipline, is expected to help facilitate our return to the mid-range of our targeted debt levels in 2008.

DEFINED PLAN

The Canadian Natural team is proud to be able to provide a transparent strategy and growth profile to its investors. We still target to grow, over an extended period, 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.

In addition to the production growth aspect of the plan, the migration of the production mix from one dominated by natural gas and heavy crude oil to one dominated by light crude oil and natural gas means that the economic sustainability of the organization is enhanced throughout the business cycle. Reducing overall exposure to heavy crude oil differentials and avoiding reliance on third parties to develop the markets for our products was a key consideration in our plans.

The Defined Plan, however, is not a static entity. We continually adjust and refine this Plan to ensure it optimizes returns. For example, our reaction to inflationary pressures has altered the timing of organic natural gas expansion, while the acquisition of ACC lands has increased short term production and greatly expanded the long term development potential of the organization.

Similarly with respect to heavy crude oil developments and future phases of the Horizon Project we will continue to steward capital in the optimal fashion. While we have the assets and drive to significantly grow the business, this will not occur at all costs. Project timing will be accelerated or deferred to optimize development economics. While we are currently benefiting from high commodity prices we believe it to be imprudent to assume this continues for planning purposes and so we insist on more conservative price assumptions in our long-term planning models. Over that long-term we still target 10% growth but the current cost environment means that we must be even more diligent in optimizing that Plan.

Management would like to again thank our entire team for continuing to deliver the Plan. We believe that Canadian Natural has the people, assets and plan 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

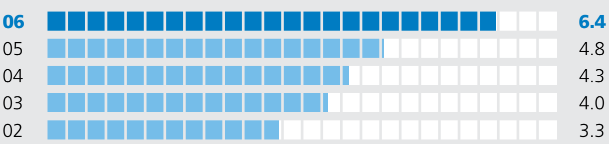
N. MURRAY EDWARDS
Vice-Chairman of the Board

JOHN G. LANGILLE
Vice-Chairman of the Board

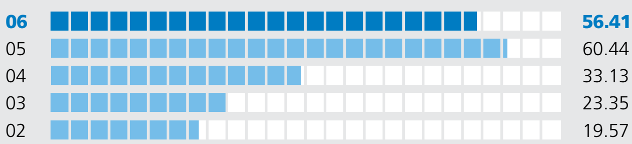
STEVE W. LAUT
President &
Chief Operating Officer

PROGRESS ON OUR FOUR PERFORMANCE INDICATORS (CONTINUED)

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



Conventional net asset value per share
(C$/share, adjusted for 2004 and 2005 share splits) SEE NOTE 5 ON PAGE 102 FOR CALCULATION



Our World-Class Team

We strive to achieve a balance of technical skills, leadership, and a strong organizational culture. These are the people that make our team. As a team, we remain committed to "developing people to work together to create shareholder value by doing it right with fun and integrity". The growth of our business has resulted in our team growing by 620 employees during the year, ending 2006 with 3,700 employees.

Lonnie Abadier, Walday Abeda, Hazel Aberdein-Quirie, Mona Abravesh, Libby Ackerley, Trevor Ackerman, Janine Adams, Mike Adams, Debra Addinall, Kike Aderibigbe, James Agate, Jennifer Ahern, Sarshar Ahmad, Sarah Aho, Garrisen Ailsby, Fiona Aitken, Adebayo Akinpelu, Sina Akinsanya, Joseph Albano, Chris P. Alderson, Bruce Alexander, Gregory Alexander, Elena Algazina, Mohi Alghazali, John Allan, Selena Allan, Jill Allen, John Allen, Simon Allerton, Devin Allibone, Karen Almadi, Michael Almasi, Gordon Almond, Robert Almond, Jocelyn Alonso, Nelson Alook, Cindy Alpaugh, Laurel Alston, Susan Alwood, Ulises Amador, Gregory Amalia, Joann Aman, Traore Amara, Clark Ambler, Jonah Amedu, Jonah Amedu, Donald Ames, Roxanne Amrolia, Sylvia Anaka, Eric Andersen, Jan Andersen, Troy Andersen, Allan Anderson, Barry Anderson, Bruce Anderson, Findlay Anderson, Georgina Anderson, Jeremy Anderson, Kelvin Anderson, Leonard Anderson, Linsey Anderson, Murray Anderson, Perri Anderson, Richard Anderson, Steve Anderson, Tony Anderson, Peter Andrekson, Janet Andrew, Bob Andrews, Todd Andrews, Erica Andrusiak, Sherley Angers, Carolyn Angus, Shehzad Anjum, Kathryn Anthony, Helen Antle, Kathy Antonishyn, Shelley Antonuk, John Argan, Humberto Arias, Roxcie Arkinstall, James Arkley, Anthony Armstrong, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Neil Arsenault, Paul Arsenault, Bala Arunachalam, Anthony Ash, Jim Asmus, Jacqueline Asso, Sialla Assohou, Francklin Assoko-Mve, Andrew Astalos, Maguy Atheba, John Atkinson, Kyle Atkinson, Nicole Atkinson, Gordon Au, Maurice Aubin, Jason Auch, Bernard Auger, Richard Augustyn, Maria Avila, Kevin Babuik, Michael Baddeley, MaryAnn Baes, Brian Bahlieda, Dave Baier, Janice Baik, Michael Baik, Dwayne Bailer, Rod Bailer, Judy Bailey, Robert Bain, Leon Bakaas, Chris 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, Corrie Balogh, Ladji Bamba, Mamadou Bamba, Neville Banak, Darwin Banash, Junet Banawa, Rechelle Baniqued, Bob Banks, Teresa Banny, Chris Bantli, Inge Bantli, Lawrence Baraniuk, Garry Bardoel, Larry Bardoel, Pamala Bare, Sharon Barker, Steve Barker, Michael Barnes, Michael Barnes, Beata Barnett, Javier Baroja, Deborah Barr, Kenneth Barrett, Phrona Lisa Barrett, Barry Barrs, Darcy Barry, Carol Barss, Carrie Barter, Marty Bartman, Julius Bascon, Calvin Bast, Michael Batac, Cheryl Bateman, Lisa Bateman, Daphne Bates, Selena Bath, Mark Batovanja, Brenda Battyanie, Jeremy Battyanie, Jackie Bauer, Lydell Bauer, Ronnie Bauer, Kevin Bauman, Breanne Bawol, Veronica Bayley, Raymond Bazan, Denise Beairsto, Colin Beaman, Harold Beamish, Chad Beaton, Aura Beattie, Laurier Beaunoyer, David Bechtel, Brent Beck, Chris Becker, Elke Becker, Holly Becker, William Bedford, Gurpreet Bedi, Kevin Beebe, Ewan Beenham, Loren Behrens, Nawar Belah, Jeremy Belair, Guy Belanger, Kelly Belanger, Lesley Belcourt, Betty Belenky, Calvin Bell, David Bell, David Bell, Faye Bell, Jon Bell, Larry Bell, Reg Bellanger, Lorne Bellows, Remie Belmonte, Leah Belsher, Ahmed Bendahmane, Khalida Bendahmane, Brad Bendick, David Bendrey, Robert Benko, Lene Benner, Erick Bennett, Jennifer Bennett, Brad Benoit, Brad Bensmiller, Shelly Bensmiller, Chad Benson, James Bentley, Robert Bercha, Ken Berenguer, Linda Beresh, Debbie Berg, Jaimie Berg, William Berg, Jeffrey Bergeson, Becky Bergley, David Berlinguette, Henry Berlinguette, Daniel Bernardo, Joanne Berrade, Murray Bertsch, Jonathon Best, Rodney Best, Jack Besuijen, Stewart Bettinson, Ashley Bexson, Marc Bickham, Jennifer Bidlake Schroeder, Corey Bieber, Beata Biel, Douglas Bielech, Rachelle Bien-Barnard, Inge A. Biener, Monica Billings, Roger Bintz, Warren Birch, Tim Bird, Jane Birkett-Hodson, Shane Bischoff, Gillian Bishop, Hope Bishop, Jeff Bishop, Kathy Bishop, Travis Bishop, Paula Bissell, Ron Bisset, Darwin Bittner, Kevin Bjornstad, Adam Black, Chad Black, Craig Black, David Black, Kenneth Blackhall, Kerri Blackmore, Olivera Blagojevic, Michael Blair, Deana Blais, David Blake, Evan Blake, Alvaro Blanco, Chris Blatchly, Shawn Blaydes, Parrish Blizard, Judith Blomdal, Allissa Blondin, Ellen Bloomfield, Gregory Blundon, Robin Bly, Kathryn Bobye, Allan Boddy, Brad Bodnar, Dennis Boehmer, Michael Boer, Kent Boerrichter, Kyle Boerrichter, Darcy Boettger, Warren Bogelund, Marty Boggust, Gordon Bohrson, Claude Boily, Peter Boisvert, Michael Bolianatz, Greg Bolin, Marguerite Bonnet, Patricia Booklall, Jayne Booth, Charlene Boraas, Barry Borbely, Adriana Borbon, Albert Bordeleau, Michael Born, Jon Borstel, Blair Bosch, Dave Bosch, Dave Bosek, Greg Boshaw, Enrica Bosoni, Keith Bottriell, Suzanne Boudignon, Rick Bourassa, Sheldon Bourassa, Delwood Bourke, Daryl Bourque, Daniel Boutin, Mark Bowden, Jim Bowers, Slade Bowers, Clinton Bowles, Gordon Bowzaylo, Dale Boychuk, Doug Boyd, Patrick Boyd, Charline Boyer, Lorraine Boyle, Neil Bozak, John Brabec, Dave Bracey, Bryan Bradley, Hugh Bradley, Jason Bradley, Peggy Bradner, Jan Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Jo-Ann Brake, Jessica Braley, Myron Brataschuk, Brad Braun, Colin Brausen, Tara Brechin, Sharon Breitkreuz, Joseph Breland, Paul Breland, Shawn Brennan, Barry Brenton, Roxane Bretzlaff, Olaf Breukel, Butch Briggs, Denis Brisebois, Robert Brisson, Donald Britton, Frances Broadfoot, Shawn Brockhoff, Kelly Broda, Brian Brodbin, Dwayne Brodziak, John Brogly, Bill Bromling, Murray Brooker, Andrew Brooks, Dennis Brooks, Tanya Brooks, Jeremy Brown, Julie Brown, Ronald Brown, Steve Brown, Tracy Brown, Tyler Brown, Leo Browne, Cathy Brownell, Robert Brownless, Christopher Bruce, Shelly Bruce, Fred Brugger, John Brule, Jason Bryant, Peter Bryenton, Sean Bryson, David Buchan, Stewart Buchan, Joseph Buchanan, Danny Buchinski, Natasha Buckland, Gordon Buckshaw, Linda Buczkowski, Bill Budd, Raymon Bueckert, Ian Bulloch, Don Bumstead, Douglas Bumstead, Alan Bunyan, Clarence Bur, Rick Burchby, Trevor Burchenski, Ian Burchette, Jeffrey Burdett, David Burdziuk, Brent Bureau, Keith Bureau, Grant Burgess, Alastair Burke, Crystal Burke, Lyle Burke, Gayle Burnett, Ken Burnham, J. Rick Burns, Sharon L. Burns, Barry Burt, Gerald Burtch, Corinne Burton, Lisa Bush, Rosemary Bussi, Terry Butchart, Bob Butterworth, Ronald Butts, Leanne Butz, Tricia Butz, Arnie Bye, Mike Byrtus, Irina Byvald, Joe Cabay, Moraima Caceres, Glennie Cadieux, Mark Cadman, James Cadrain, Simon Cains, Laura Calder, Leslie Calder, Byron Caldwell, Patrick Caldwell, Tom Callaghan, Darren Calliou, Richard E. Calliou, Dean Cameron, Mike Cameron, Brian Campbell, Catherine Campbell, Clayton Campbell, Dean Campbell, Doug Campbell, Earl Campbell, Nancy Campbell, Robert J. Campbell, Shawn Campbell, Valerie Campbell, Andre Campeau, Wayne Campeau, Gregory Cane, Brad Canning, James M. Capjack, Barry Carabin, Kathleen Carbury, Fred Cardinal, Lee Cardinal, Myles Cardinal, Sharon Cardinal, Wayne Cardinal, Suzie Careless, Jim Carey, Joey Carifelle, Ian Carleton, Stephanie Carlson, Wes Carlson, Albert Caron, Rochelle Caron, Michael Carr, Diego Carrera, Kim Carrol, Ian Carroll, Shayne Carroll, Robert Carson, Eduardo Cartaya, Marilyn Carter, Gary Case, Mary-Jo Case, Trevor Cassidy, Lance Casson, Mike Catley, Steve Caven, Richard Cawaling, Chris Cawley, Ciara Celis, Marco Celis, Samuel Cervantes, Andrew Chaisson, Sachi Chakravarty, Erin Chamberlain, Lise Champagne, Alan Chan, Anly Chan, Jack Chan, Jik Chan, Sarah Chan, Tim Chan, Wayne Chandler, Koh Chang, Calvin Chapman, Melody Chapman, Todd Chapman, Deon Chappell, Harry Chappell, Darryl Charabin, Cynthia Chartrand, Roger Chartrand, Susan Y. Chase, Leon Chateauneuf, Arundhati Chatterjee, Sumit Chatterjee, Teecy Chau, Siddique Chaudhry, Dawn Chau-Lam, Gary Chaulk, Jackson Chaves, Rinet Maria Chaves-Thissen, Carl Cheeseman, Brian Chen, Mike Chernichen, Bill Chernish, James Cheung, Ricardo Chiang, Gloria Chick, Patricia Childs, Al Chin, Melaine Chin, Sharon Chin, Jamie Chisholm, William Chiverton, Randall Chodzicki, Jessica Choi, Raymond Chong, Brett Chorney, Wayne Chorney, Lynn Chotowetz, Sherry Chow, Shayela Chowdhury, Alphonse Chretien, Mark Christensen, Ruth Christensen, Heidi Christensen Brown, Marianne Christianson, David Christie, Shawn Christie, Steven Christie, Rob Christopher, Andy Chu, Ken Chudleigh, John Chuiko, Sharon Chung, Heather Church, Ronni Church, Kadidiatou Cisse, Magda-Christina Ciulavu, Michael Clapham, Bryan Clapperton, William Clapperton, Amanda Clark, Andrea M. Clark, Brent Clark, Evan Clark, Janice Clark, John Clark, Ken Clarke, Martha Clarke, Olivia Clarke, Sanja Clarke, Shandon Clarke, William J. Clarke, Walter Clarkson, Greg Clegg, Cory Clement, Leah Clewes, Brooke Coburn, Dale Coburn, Judith Cochran, John Coers, Charles Coffey, Rob Coles, Marc Collie, Grant Collier, Curtis S. Collins, Richard Collins, Robert Collins, Rod Collins, Roy Collison, Adam Collyer, John Coloso, George Coman, Ron Compton, Rebecca Conacher, Mark Connellan, David Conybeare, Brad Cook, Chris Cook, Anna Cooke, Lori Cookson, Rob Coolen, Gary Coombe, Kent Cooper, Jason Copeland, David Coppard, Robert Coppard, Jean Corbiere, Mark Corell, Elaine Coreman, Rosetta Cormier, Rosario Corral, Luis Correal, Jim Corson, Lorenzo Cortes, Neil Cortmann, Harry Costello, Neil Costeloe, Brent Cote, Sanga Coulibaly, Dougie Coull, Kim Coulter, Jack Courchene, Robert Courchesne, Kathryn Courtney, Dave A. Cousins, James Coutts, Gordon Coveney, Terry Cowan, Richard Coward, Keith Cowger, Cath Cowie, Jonathan Cox, Randy Cox, Wade R. Cox, Nigel Crabb, Harry Crabtree, Layne Craig, Bruce Crain, Allen Crawford, Marina Crawford, Michael Crawford, Paul Crawford, Beverley Creed, Donald Cretney, Roger Crichton, Terri Crockett, Shane Croft, Stefan Croft-Bednarski, Christopher Cross, Lloyd Cross, Teresa Cross, Camille Croteau, Phil Cruickshank, Linda Cruttenden, Anthony Csabay, Will Csanyi, Jeff Cullen, Corinna Culler, Darrel Cunningham, Davis Cunningham, Tara Cunningham-Canfield, Arley Currie, David Currie, Brent Curtis, Paul Curtis, Troy Curzon, Dale S. Cusack, Kenneth Cusack, Pat Cusack, Réal Cusson, Midge Cuthill, Don Cutting, Chris Cyr, Les Czernicki, Kevin d'Abadie, Victor Daboin, Greg Dacyk, Fakhry Dadashev, Gary Dahl, Hamid Dahmani, Eliane Dakaud, Brittany Dalby, Patrick Dale, Joey Daley, Layne Dalgetty-Rouse, Gary Daly, Loren Damer, Walter M. Danchak, Beth Daniel, Mike Danis, Gene Danyluk, Peter Danyluk, Alan Dar, Eric Dargis, Mark Darling, Lynne Darlington, Merl Darragh, Wigo Dascalescu, Bruce Davidson, Graham Davidson, Louise Davidson, Scott Davidson, Todd Davidson, Brian Davies, Lynne Davies, Frank Davis, Graham Davis, Greg Davis, Kenneth Davis, Randall Davis, Robert Davis, Sarah Davis, Jeffrey Davison, Peter Davison, Leonard Dawe, David Day, Robert Day, David Dean, Harry Dean, Martha Dean, Douglas DeAvila, Trevor Debler, Ryan DeBruyne, Derek Dechaine, James Dechaine, Raymond Dechaine, Roland Dechesne, Sheldon DeFord, Phil DeGagne, Mervin J. Degenstien, Barbara Deglow, Bonnie Deis, Eric deKock, Ryan DeLeeuw, Natalie Delfs, Franco Dell'Ovo, Benita DeLorenzo, Benito DeLorenzo, Brent Delorme, Michael Delorme, Minette DelosReyes, Liana Delpinto, Tom DeMaid, Charlene DeMone, Antonia Deniega, Susan Dennis, Lee Denny, Shirley Denny, Colin Derby, Edward Deren, Tom Dereniwski, Shane Derlukewich, Robbert deRuiter, Semir Dervovic, Eugenie Dery, Ajit Desai, Laurie A. Devey, Fraser Dewar, Todd Dewhurst, Debbie Dewis, Robert Dewis, Karen Deyaegher, Maldip Dhaliwal, Vikas Dhawan, Keith Diakiw, Karim Diallo, Harry Diamantopoulos, Sumara Diaz, Bob Dicken, Garry Dickie, Blair Dickson, Cameron Dickson, Stu Didyk, Sue Didyk, Aldo DiFlumeri, Irene Dikau, Anne Dillon, Mike Dingley, Greg Dingwell, Ronald Dinkel, Hubert Dinn, Issiaka Diomande, Gayle Dionne, Mamadou Diouf, Tim Ditchburn, Al Dixon, Kathleen Dixon, Robin Dixon, Trent Dixon, Angela Dobb, Derrick Dobrowski, Leanne Dobson, Linnae Dobson, Edward Dochuk, John Dodman, Erin Doepker, Kelly Doepker, Kim Doepker, Ritchie Doering, Jordy Doerksen, Patrick Dolan, Amy Dolomount, Conrad Dombowsky, Kelly Dombrosky, Brenda Dombrova, Dan Domke, Kyle Donald, Scott Donaldson, Claire Dong, Tim Donkersloot, Veronica Dooling, Tim Dootka, Allen M. Dorey, Olga Dost, Réal Doucet, Eddie Douglas, Dahl Dow, Angela Dowd, Jeff Dowd, Phil Downes, Todd Draper, Wayne Draper, Kenton Dreger, Brian Drew, Lorna Drilon, Don Drindak, Colleen Drury, John Drury, Calvin Duane, Rafael Duarte, Sean Dubelt, Jeramie Ducharme, Rick Ducharme, Ryan Duckworth, Albert Duczek, Jon Dudley, Rhonda Dudley, Alan Duffy, Morley Dufour, Simon Dugdale, Douglas Duguid, Albert Duhaime, Doug Duke, Barry Duncan, Lois Duncan, Sean Duncan, Ashley Duniece, Dale Duniece, Graham Dunlop, Jill Dunlop, Robert Dunn, Keith Dunnett, Judy Dunsmuir, Lyle Dupuis, Dariela Duran, Harvey Dutchak, Faron Duthie, Terry Dyer, Eugene A. Dyjur, Krzysztof Dzwonek, Julina Eagleson, Gary Earl, Kevin Earle, Julie Easthope, Suzanne Eaton, Sean Ebert, Jim Eby, Greg Ecker, James Edens, Robert Edgar, Josephine Edoukou, Gordon Edward, Dave Edwards, Sue Edwards, Fred Eefting, Cindy Egden, Christopher Ehresman, Brian Eitzen, Nicole Eitzen, Devin Ekdahl, Wassim ElChayati, Douglas Elder, David Eley, Craig Elies, Carole Eliuk, Anthony M. Ell, Robert Elliott, Karen Ellis, Mohamed El-Naas, Tina Emery, Jerry Enders, Rommel Engler, Joanne English, Kenny Ergang, Terry Erickson, Kresten Eriksen, Polina Ersh, Rick Estrada, Andrew Etele, Samantha Etherington, Kim Evanoff, Lee Evans, Randy Evans, Tim Evans, Leila Eveleigh, Maureen Evers-Dakers, Clayton Eves, Doug Eves, Frederick Ewen, Laura Ewen, Douglas Eynon, Kris Eyolfson, Leonard Fabes, Lawrence Facchina, Denis Fagnan, Heather Fahey, Andy Fankhauser, Chelsea Farrell-Dreger, Randy Farrer, Travis Farrer, Krista Farris, Stefa Fassina, Jayme Faszer, Arthur Faucher, Everette Fauth, Jamal Fayad, Karman Fayant, Renee Fayant, Tanya Fayant, Tyson Feairs, Brian Fehr, Darwin Feil, Ira C. Feland, Warren Feland, Andre Yves Felix Tchicaya, Kurt Fenrich, Ken Ference, Brad Ferguson, Helen Ferguson, Mark Ferguson, Neil Ferguson, Roy Ferguson, Scott Ferguson, Mario Feria-Estrada, Cory Fernets, Ron Fewer, Darren Fichter, Tiziana Ficocelli, Alan Fiddes, Jane Fielding, Sherman Fifield, Chris Filgate, Michael Filipchuk, Neil A. Findlay, Kelly Finigan, Bob Finlayson, James Finlayson, Chad Finnebraaten, Timothy Finnigan, Kristin Finot, Tanya Fir, John Fisera, Calvin Fisher, Darya Fitsko, David Fittkau, Bill Fitzgerald, John Fitzgerald, Sandra Fitzpatrick, Daniel Fitzsimmons, Colleen Flamont, Ken Fleck, Sean Fleming, Rodney Flett, Trevor Flood, Mark Flynn, Edmond Foisy, Justin Foisy, Ryan Folkerts, Gregory Fontaine, Leo Fontaine, Robert Fontaine, Roger Fontaine, Lynn Foo, Harris Foote, Adele Forcade, David Foret, Curtis Formanek, Randy Formanek, Devon N. Fornwald, Leslie Forrester, Alastair Forsyth, Chantal Fortin, Donald Foster, Dwayne Fotty, Kevin Foulds, Scott Fouracres, Jim Fowler, Donald Fox, Donna Frame, Roger France, Vicky France, Ron Frank, Richard Franken, Allan Frankiw, Blaine Franklyn, Shelley Franssen, Leonard Fraser, William Fraser, Barry Frazer, Ken Frazer, Ted Frederickson, Michael Freeman, Stacey Freidin, Peter French, Roger Frere, Jared Frese, Kurt A. Freyman, Brad Friesen, David Friesen, Kenneth Friesen, Monte Friesen, Kevin Frith, Tracy Frith, David Fritz, Andrei Frizorguer, Frank Frosini, Colin Frost, Scott Froude, Karen Fujimoto, Doug Fukushima, Jim Fung, Sarina Fung, Leonard Furlong, Ted Furuya, Josephine Gaddi, Mamta Gadhiya, Leonard Gadowski, Sharon Gaehring, Kelly Gagne, Scott Gair, Larry Galea, Jaylyne Galey, Ron Gall, Bob Gallant, Michael Gallon, AWilliam Galloway, Yoko Galvin, Andreas Gamp, Bob Gandhi, Vovel Gapaz, Isabel P. Garbin, Carlos Garcia, Daina Gardiner, Doug Gardner, Lynette Gardner, Jon Gareau, Tim Gareau, Glen Garton, Stan Garwon, Carlos Garzon, Mark Gaspich, Vanessa Gaudreau, Joseph Gaugler, Maurice Gauthier, Neil Gauthier, Klaus Gautschi, Steve Gavronsky, Melanie Gaw, David Geleta, Lesley Ann Gemmell, Neil Genge, Patricia Gentles, Devin George, William George, James Georget, Kimberley Gereluk, Jim Gergely, Matthew Gering, Grant Gerla, Michel Germain, Raymond Germain, Robert Germain, Colin Germaniuk, Albert Gervais, Karlene Gervais, Marc Gervais, Paul Gervais, Bob Gerwing, Sheldon Getson, Beryl Gettings, Clark Getz, Glen Getz, Stanley Getz, Ken Getzinger, Zoheir Ghaddar, Chad Gibson, Douglas Gibson, Charles Giddings, Shaun Giefer, Jean Giesbrecht, Todd Giesbrecht, Dwayne Giggs, Garth Gilbert, Elias Gildeh, Tamara Giles, Gladwin Gill, Ian Gill, Ralph Gill, Perry Gillam, John Gillatt, John Gillespie, Ron Gillespie, Sharen Gillett, Erin Gillis, Sandra Gillis, Vicki Gillis, Martin B. Gillund, Justin Gilmour, Scott Gilmour, Douglas Ginn, Stewart Girbav, Ben Gisby, Eugenio Giuliani, Marvin Gladue, Russell Gleed, John Glennon, Jason Glubish, Duane Goetz, Peter Goetz, David Golden, Cody Gomuwka, Elaine Gong, Brian Gonsalves, Jose Gonzalez, Yvonne Gonzalez, Ian Gordon, James Gordon, Winston Goretsky, Jennifer Gorman, Rhonda Gosse, Yvon Gosselin, Allan Gould, Todd Gould, Antonella Goulet, Sandra Goundrey, Trevor Gowman, John Graca, Tara Grace, Marah Graham, Trevor Graham, Austin Grant, Harry Grant, Ronald Gray, Sheila Gray, John Greaves, Linda Green, Shilo Green, Wayne Green, Marc Greenan, Cory Greenawalt, Shannon Greene, Theresa Greene, Richard Grieve, Edmond Griffiths, Sherisse Grillone, Robert Groenen, Leo Groenewoud, Robert Grover, Daryl Grundner, Neil Guay, Trevor Guay, Don Guglielmin, Gilbert Guigon, Aliya Gulamhusein, Karim Gulamhusein, Robert Gullion, Shane Gullion, Swarna Gunaratne, Carolyn Gunderson, Alan Gunst, Ashok Gupta, Rustam Guseynov, Edward Gushnowski, Terry Gusnowski, Graham Gustafson, Harold Gutek, Fabio Gutierrez, Bartley Haahr, Alain Habel, Rodney Haberlack, Hamid Habibi, Violet Haddad, Leisa Haddleton, Resad Hadzismajlovic, Keri Hagemann, Chad Hagstrom, Keith Hague, Wondafrash Hailu, Sam Hajar, Shemin Haji, Zohreh Hajibeygi, Dan Halaburda, Jeremy Hale, Montie Hale, Dean Halewich, Rick Halkow, Barry Hall, Charles Hall, Donald Hall, Kathy Hall, Michael Hall, Shane J. Hall, Todd Halladay, Patricia Halldorson, James Hallett, Robert D. Hallett, Charlene Halter, Larry Hamende, Darcy Hamilton, Jeremy Hamilton, Tim Hamilton, Kevin Hamm, Michael Hammel, Larry Hammell, Rick Hammond, Chrystal Hamori, Bryan Hamula, Mei Han, Zonghai Han, Brad Hancock, Anne Hand, Carol Handley, Warren Handley, Tracy Hanline, Karl Hann, James Hansen, Todd Hansen, Cheryl Hanson, Judy Hanson, Leland Hanson, Brent Harbin, Leon Harder, Carson Harding, Kent Hardisty, Ken Harke, Julia Harker, Brent Harle, Les Harley, Angela Harlos, Erik Haroldson, Ray Harper, Chad Harris, Coby Harris, Jody L. Harris, Murray Harris, Roger Harris, Ron Harris, Stephen Harris, Clayton Harrison, Dylan Harrison, Patrick Harrison, Randy Harsany, Brent Hartley, Bud Hartley, James Harty, Lorne Harty, Mike Harty, Amie Harvey, Greg Harvey, Janet Harvey, Jerry Harvey, Julie Harvey, Michael Harvey, Cory Harvie, Cheryl Hasenclever, Colin Hastings, Iain Haston, Ewen Hatchwell, Bryan Hattebuhr, Christine Hattebuhr, Dale Hattebuhr, Barret Hatton, Wayne Hatton, Dave Haub, Willow Hauber, Ross Hauger, Wayne Hausch, Betty Hayden, Cameron Hayden, Nancy Hayes, RJoey Hayward, David Haywood, Sean Head, Jay Heagy, Brad Hearn, Larry Heath, April Hecht, Terry Heck, Ken Hedstrom, Christopher Heffner, Della Hefford, Robin Hein, Mahmud Hejni, Tim Helle, Carey Hellman, Barton Henderson, Steven Hennessey, John Hennessy, Anita Hennig, Leona Hennig, David Henry, Reid Henry, Jackueline Herauf, Kim K. Herbst, Brad Herman, James Herman, Justin Herman, Judith Hermann, German Hernandez, Luis Herrera, Edwin Herrenschmidt, Coreen Herring, Michele Herron, Keith Heslop, Brian Hess, Cara Hess, Dorain Hessel, Tyson Hessler, Brenda Hetman, Tia Hickie, Kim Hicks, Rodney Higa, Andrew Higgins, Rachelle Higgins, Charlene Hill, Gordon Hill, Steve Hill, Ernie Hilland, Jesse Hillebrand, Jeff Hillier, Christie Hillis, Arnold Himschoot, Ken Hingley, Katarzyna Hinks, Jim Hlewka, Margaret Ho, Lee Hoang, Donald Hoar, Karyn Hobbs, Lee Hodder, Barry Hodgan, Gary Hodge, Barbara Hofer, Miles Hogaboam, Joanne Hogg, Kevin Hogg, Krista Hogg, Alan Hoiland, Kevin Hoium, David Hollett, Donald Holley, Doug Holman, Richard Holman, Donald Holmen, Cliff Holmerson, Chris Holmes, Ian Holmes, David Holt, Brett Holthe, Clayton Holthe, Dennis O. Holthe, Shannon Hood, Hans Hoogendam, Graham Hook, Keith Hornseth, Kimberley Horvath, Richard Horvath, Jon Horyn, Renita Hoskins, Lance Hoskyn, Tony Hou, Jeff Houck, Helena Houghton, Sherri Houle, John Howard, Trapper Howard, Kristy Howe, Shelagh Howell, Angela Hoza, Curtis Hrdlicka, Jianxin Huang, Ti Huang, Kyle Huculak, Helen Hudson, Paul Hudson, Sandy Huebner, David Huff, Jeremy Hughes, Mark Hughes, Eun Ju Huh, Bryan Huk, Riley Hull, Wendy Hum, Terry Humbke, Darren Humphries, Manpreet Hundal, Ian Hundeby, Jennifer Hunt, Kevin Hunter, Robert A. Hunter, Tom Hunter, Vivian Hunter, James Hurdal, Bradley Hurtubise, Chad Huseby, Taira Hutchings, Daniel Hutchinson, Dennis Hutchinson, Ray Hutscal, Bruce J. Hutt, Ewart Hutton, Greg Huva, Stephen Hygard, Nathan Hylton, Bonnie Hynes, David Hynes, Scott Hyrcha, Sarah Hyslop, Gerard Iannattone, Pina Iannattone, Sherry-Lynn Ibey, Matthew Ilchuk, Detlev Imorde, Dominic Ing, Alexander Inglis, Jennifer Inglis, Max Inglis, Brad Inman, Rebecca Innes, Matt Inscho, Scotty Iron, Jamie Irons, Jeff Irons, Dora Irsa, Ted Irwin, Darren Isele, Floyd Isley, Peter Iuni, Karen Ivan, Arlette Ivany, Jeff Iwanaka, Wallace Jack, Daniel Jackson, Judy Jackson, Niki Jackson, Ronald Jackson, Russel Jackson, Victoria Jackson, Ken Jacobson, Albert Jacula, Curtis Jacula, Marci Jacula, Todd Jacula, Hamid Jafari, Charu Jain, Vivek Jain, Michael Jaindl, Boris Jakulj, Annie Jalotjot, Stephen Jamam, Chris James, Jeff James, Bob Jamieson, Nigel Jamieson, Maria Jancewicz, Marc Janke, Dale Jans, Steve Jansky, Peter Janson, Kelly Janus, Leonard Janzen, Crystal Jardine, Nancy Jarman, Calvin Jarratt, Dave Jarrell, Jim Jarvis, Joanie Jarvis, Mark Jean, Wendal M. Jellison, Leslie Jenkins, Jason Jenner, Lindsay Jenner, Michael Jennings, Brent Jensen, Justin Jensen, Kevin Jensen, Parry Jensen, Mark Jespersen, Iain Jessiman, Qi Jiang, Ramon Jimeno, Terry Jocksch, Juan Joffre, Brent Johns, David Johnson, Evan Johnson, Jeffrey Johnson, Marlene Johnson, Mitzi Johnson, Neville Johnson, Stacy Johnson, Theresa Johnson, Holly Johnston, Joe Johnston, Michelle Johnston, Neil Johnston, Chris Johnstone, Janet Johnstone, Dan Johnston-Watson, Victoria Jolliffe, Brent Jones, Delbert Jones, Ed Jones, Gareth Jones, Harley Jones, Lori Jones, Mark Jones, Pamela Jones, Tammy Jones, Wayne Jones, Martyne Jongerius, Paul Joo, Damian Jordan, Jaime Juan, Albert Junco, James Jung, Sandy Jung, Chris Jungen, Miriam Juniper, James Jurome, Melanie Juurlink, Paul Kabatek, Asif Kachra, Mary Kadri, Carol Kadutski, Jonathan Kadutski, Raymond Kahanyshyn, Krista Kaiser, Myra Kalakailo, Dustin Kalinsky, Sheron Kalirai, Derek Kalynchuk, Elizabeth Kaminski, Ari Kandasamy, Larry Kane, Shari Kane, Dwayne Kaprowski, Tom Karpa, Doug Kary, Lynn Kasper, Shelina Kassam, Amy Kastelic, Beverley Katay, Myles Kathan, Deanne Katnick, Hassan Katrip, Travis Kavalec, Olga Kay, Christopher Kean, Gregory H. Keats, Philip Keele, Christopher Keim, John Keith, Joe Kelenc, Marina Keller, Rayelene Kellock, Alphonsus Kelly, Christine Kelly, David Kelly, Eileen Kelly, Jeff Kelly, Ken Kelly, Tim Kelly, Simon Kelsey, Greg Kemp, Stephen Kempton, Denise Kennedy, Wayne Kennedy, Val Kenyon, Rob Kerr, Ryan Kerr, Blair Kessler, Lori Ketchuk, Greg Ketter, Minh Kha, Ajmal Khan, Amjad Khan, Shehnaz Khan, Shaalini Khanna, Tatiana Kharitonova, Kimberly Kielt, Leonard Kiez, Todd Kilback, Iain Kilpatrick, Heather Kim, Curtis Kimler, Douglas King, Richard King, Tasha Kingsbury, Peter Kinnear, Cam Kinniburgh, Marvin Kinsman, Sebastian Kirstine, Tony Kirtley, Cryssy Kish, Marlene Kissel, Robyn Kissel, Shane Kissel, Marlene Kissoon, Bob Kitsch, Myles Kitt, Curtis Kiyawasew, Jody Kiziak, Jim Klaffl, Cody Klatt, George Klemak, Douglas Klug, Jeff Knibbs, Allen Knight, Anita Knipe, Darcey Knoblich, Olga Knopov, William Knouse, Ernie Knowles, Tamara Knox, Dwayne Kobes, Russ Kobi, Corey Koble, Barney Kobzey, Bill Koch, Kouakou Koffi, Sylvain Koffi, Shaju Koickel, Blair Koizumi, Lutz Kolberg, Eva Komers, Cameron Komm, Hadizata Konate-Rassi, Martin Kondor, Brent Kondratowicz, Ibrahim Kone, Lacina Kone, Sergey Korchagin, Brent Korolischuk, Rick Koshman, Jennifer Koslowski, Brent Kosowan, Doug Kosowan, Vladimir Kostic, Diane Kostiuk, Kevin Kostrub, Ann Kostyshyn, Stacey Kotelniski, David Kotsibie, Marcelin Koua, Philippe Kouadio, Hermann Kouame, Randall Kovalenko, Joanne Kowalewski, Richard Kowalski, Kevin Kowbel, Trevor Kowk, Adam Kownatka, Magdalene Kownatka, Dennis Kozak, Teresa Kozina, Russell Kraeleman, Cameron Kramer, Andrew Krancz, Lyndon Krankowsky, Trevor Kratz, Bryan Krause, Gary Krause, Trevor Krause, Todd M. Kreics, Jeffrey Kreiser, Murray Kreiser, Patti Krekoski, Daniel Krentz, Blayne Kress, Connie Kriaski, Michael Krips, Udaya Kumar Krishnan, Heather Krislock, Linda Kroeker, Peter Krol, Vanja Krtolica, Gabriel Krywolt, Harriet Kubi, Chris Kubisch, George Kucy, Warren Kuefler, Wayne Kullman, Vikas Kumar, Jeff Kuntz, Tanya Kuntz, Frank Kurucz, Brian Kutash, Steve Kuzmak, Keith Kwan, Russ Kwan, Kelly Kwiatkowski, Angele Kwon, Karen Kyffin, Bob Kyllo, Robert Laboucane, Stanley LaBrash, Marc Lachambre, Gernot Lackner, Jocelan Ladner, Phillip Laflair, Philip Lafond, Anny Lafontaine, Levi Lafrance, Ronald LaFrance, Cassandra Lai, Philip Lai, Theresa Lai, Ronald Laing, David Lake, Edward G. Lalande, Munira Lalji, Elaine Lam, Sam Lam, Kurtis Lamb, Terri Lamb, Dee Lambert, Dino Lambert, Richard Lameman, Sharon Lamontagne, Dave Landers, Marc Landry, Marcel Landry, Michel Landry, Stephen Lane, Raul Lanfranchi, Marc Langford, John Langille, Carolyn Langpap, Amanda Lapointe, Krista Lapointe, Michelle Lapointe, Pamela Lapp, Melvin Lapratt, Gianni Larice, Corey Larocque, Leon LaRose, Katherine Larsen, Dave Larsh, Penni Larson, Rob Larson, Robert Larson, Bengt Larsson, Ronald Lasek, Reno Laseur, John Lasocki, Barry Lassiter, Daniel Lastiwka, William Latchuk, Joan Latter, Krista Latunski, Peter Latus, Bob Lauder, Karen Laurin, Steve Laut, Michal Lavi, Bernard Lavoie, Iris Law, Oliver Law, Ken Lawless, Darron D. Lawrence, Ewen J. Lawrence, Fred Lawrence, Lindsey Lawrence, Shareen Lawrence, Brian W. Lawson, Gordon Lawson, Martin Lawson, Dave Laycock, Chelsea Layden, Paul Layland, Sharon Layton, Greg Lazaruk, Brian Leach, Doug Leach, Trevor Leach, Albin Leaf, Rodney Leblanc, Kristopher Lechelt, Susan Leckie, Amanda Lee, Carmen Lee, Colleen Lee, Connie Lee, Fred Lee, Howard Lee, Jane Lee, John Lee, Swee Lee, Tim Lee, David Leeper, Caroline Lefebvre, Kevin Legault, Heather Leggett, Derrick LeGrow, Kris Lehocky, Thomas Lemon, Gustavo Leon, Heather Leonard, Joseph Leonard, Gary Leong, Hin Leong, Stephen Lepp, Paul Lepper, David Lesko, Gerry L. Leslie, Richard Leslie, Shane Lester, Lonnie Letawsky, Marcus Lethaby, Phil Letkeman, Don Leung, Katie Leung, Preeminence Leung, Wing-Ming Leung, Maurice Levac, Tracy Levasseur, Jean Levesque, Shelly Lewchuk, Gerald Lewis, Ryan Lewis, Katherine Leys, Larry L'Hirondelle, Guoping Li, Jun Li, Craig Liba, John Lieverse, Lori Light, Hout (Richard) Lim, Bonnie Lind, Jessica Lind, Penny Linden, Katherine Linder, Ewen Lindsay, Shari Lindsay, Trina Lineger, Janice Linehan, Yuri Lipkov, Tracy Little, Tony Littlefair, Dennis Liu, James Livingston, Michael Livingstone, Cam Lizee, Dale Lloyd, Debby Lo, Sharon Lo, Conrad Loch, Richard Lock, Fred Locke, Fred Locke, Kendall Locke, Darren Loder, Rod Loewen, Joy Lofendale, Ian Lofthouse, Charlene Logan, Randal Logelin, Rodney Logozar, Jorge Lombardi, Craig Long, Wade Longmore, Dallas Longshore, Sheldon Longson, Herb Longworth, Kai Loo, Roger Lopez, Nelson Lord, Catlin Lorenson, Darin Lorenson, Matthew Lorincz, Bob Lorinczy, Jose Lotito, Michelle Lou, Andrew Lough, Allan Loughran, Christopher Love, Larry Love, Mellodie Love, Lloyd Lovelace, Carrie Low, Dan Lowe, Darryl Lowe, Devin Lowe, Brad Lowell, Joe Lowen, Leah Loyola, Dave Lucas, Gerd Lucas, Serena Lucci, Crystal Lucier, Charlene Luk, Dana Lund, Wes Lundell, Clarence Lunzmann, Susie Luomala, Jason Lush, Rees Lusk, Kristin Lussier, Jim Lutyck, Wendy Lutzen-Askew, Brent Lydiatt, Ken Lynam, Wayne Lynch, John Lynn, Jim Lyons, Hong Ma, Michelle Ma, Nicky Maawia, Patricia MacCrimmon, Lindsey Macdearmid, Jason MacDonald, Mark MacDonald, Ray MacDonald, Raymond G. MacDonald, Anne-Marie MacDonell, Stephen MacDougall, Dorothy MacIntyre, Shawn Mack, Steve MacKay, Graeme P. MacKenzie, Ken MacKenzie, Kenneth Mackenzie, Ryan MacKenzie, Shawn MacKenzie, Allan MacKinnon, James William MacKinnon, Graham Mackintosh, Richard MacKnight, Mark MacLean, Susan MacLean, Callum MacLeod, Douglas MacLeod, Jamie MacLeod, Norma MacNaughton, E. Anne MacNeil, Bradley MacNeill, Angela MacNiven, Fred MacPhee, Heidi MacRae, Ronald MacSween, Bruce Maddex, Morgan Maddison, Hazel Madore, Ashley Madrusan, Gary D. Madsen, Markus Maennchen, Cathy Mageau, Mike Magnusson, Bill Mah, Curtis Mah, Jennifer Mah, Tony Mah, Cheryl Mahoney, Darren Mahony, Martin Mailhot, Al Majdzadeh, Ali Majid, Derek Major, Michelle Major, Anita Mak, Eduardo Malabad, John P. 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Tracy McFadyen, Jason McFarlane, Mark McFarlane, Bruce McFaul, Allan McGann, Frances McGlynn, Terry McGovern, Grant McGowan, Robert McGowan, Brandy McGrath, Bruce E. McGrath, Paije McGrath, Stephen McGregor, Steve McGregor, Dwain McGuire, Tom McHale, Gordon McHattie, Marianne McInnis, Alan McIntosh, Eric McIntosh, Sandra McIntosh, Kelvin McKay, Kiml McKay, Lindsey McKay, Robert McKay, Roxana McKay, Tim McKay, Dennis McKee, Robert McKendry, Tammy McKenney, Keith McKenzie, Mike McKenzie, Sheena McKinnon, Dawson McLachlan, Douglas McLachlan, Bonnie-Lynn McLaren, David McLaughlin, Keith McLaughlin, Reginald McLaughlin, John McLean, Marla McLean, Michelle McLean, Ross McLean, Joan McLellan, Ian McLeod, Eamonn McMahon, Blake McManus, Sandra McMichael, Jeff McMillan, Rod McNair, Bryan McNamara, David McNamara, Kendal McNeil, Lynn McNeil, Bill McNeill, Stephanie McNeill, Jaime McNichol, Robert McNinch, Reid McPhail, Elaine M. McPherson, Jacqueline McTamney, Maggie McTurk, Manfred Meakes, Tatrina Medvescek, Karyn Meehan-Coles, Stephen Meerman, Jai Mehta, Corrine Mei, Barry Meier, Daniel Meier, Belinda Meller, Glen Mellom, Richard Mellor, Darrell Mellott, Jean Melnychuk, Marvin Melnyk, Paul Mendes, Leila Meneses, Jiamei Meng, Jennifer Mercer, Mark Mercer, Grazyna Mercik, Nicole Mercredi, Ambereen Merk, Timothy Merk, Greg Merkel, Danny Merkley, Nathaniel Merritt, Udell Meservy, Ryan Metz, Steve Meunier, Rick Meyers, Michael Meynberg, Igor Meynin, Cindy Michalko, Gail Michaud, Barry Michelson, Murray Michie, Ian Middler, Dale Midgley, Jacek Mielczarek, Michael Mihaichuk, Marc Miiller, Jane Mikalsky, Andrei Mikhailov, Jacqueline Miko, Jeffrey Miller, Laurel Miller, Sherrie Miller, Wendy Miller, William Miller, Claire Mills, H. 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Poitras, David Pole, Marlene Pollock, Eleanor Polson, Seward Pon, Robert Pool, Chris Poole, James Pope, Colleen Popko, Jason Popko, Carol Porter, Patti Postlewaite, Jeffrey Poth, Terry Potter, Randy Pottle, Ryan Potts, Bruce Powell, Susan Powell, Laurie Power, Lisa Power, Melissa Power, Noleen Pratap, Timothy Pratt, Mike Preece, Alanna Price, Nicole Price, Travis Prins, Melodi Pritchard, Lesley Proctor, Doug Proll, Mangoueu Prosper, Sarah Proudlock, Richard Proulx, Kayla Prowse, Tammy Prudhomme, Ed Pruss, Elizabeth Pryce, Steve Pshyk, John Puckering, Yesid Edgar Puerto, Justyna Puhl, Nam Pui, Lance Pulak, Suniel Puri, Trent Pylypow, Lu Qing, Anthony Quach, Munawar Quadri, Laura Quinn, Ron Quiring, Robert Quist, Samir Qureshi, Brad Raaflaub, Mandi Rabeau, Delee Racz, Warren Raczynski, Levente Rado, Gil Radtke, Chandra Raghavan, Michael Rainey, Yina Raisbeck, Karim Rajan, Christina Ramirez, Maritess Ramirez, Ruth Ramonas, Bill Ramsay, Matthew Ramsay, Kerri Ramsbottom, Dorotea Ranola, Gregory Ransom, Jeremy Ransom, Chris Rasko, Shauna Rasmussen, Soukseum Rathamone, Stojan Ratkovic, Murray Rattray, Jason Rayner, Robert Rayner, Blair Read, Ted Reay, Deston Reber, Bernie Redlich, Donald Reed, Keith Reed, Loreena Reed, Scott Reed, Tim Reed, Michael Rees, Duncan Rehm, Carmon Reich, Alan Reid, Christopher Reid, Kerry Reid, Lilian Reid, Mark Reid, Tyler Reid, Angela Reimer, John Reiniger, Glenn A. Reiter, Wendy Reitmeier, Anil Relan, Jody Remezoff, Kelly Rempel, George Renfrew, Scott Rennie, Dustin Ressler, Russell Retzlaff, James Reynolds, Pat Reynolds, Naseem Rhemtulla, Keith Rhodes, Lisa Rich, Carolyn Richards, Charles Richards, Rob Richardson, Sandie Richardson, Wesley Richardson, William Richardson, Rick Richelhoff, Lori Richmond, William Richmond, Jeff Riddell, Robert Riddell, Bonnie Ries, Darren Riley, Dominic Riley, Dale E. Rinas, Carl Ringdahl, Gordon Ringheim, Serge Rioux, Michelle Rivard, Carlos Rivera, Daniel Rivera, Tracey Roasting, Jo-Anne Robak, Jimmie Roberts, Brian Robertson, Dale Robertson, Nancy Robertson, Stephen Robertson, Heather Robillard, Aaron Robinson, Amber Robinson, David Robinson, Donna Robinson, Gene Robinson, Julian Robinson, Scott Robson, Jaime Roche, Neal Roculan, Sheila Rodberg, Roger Rodermond, Humberto Rodriguez, Olga Rodriguez, Roberto Rodriguez, Paul Roett, Dean Rogal, Martin Rogers, Neil Rogerson, Victor Rogerson, Henry Rojo, Neil Rokos, Paul Rokosh, Louis L. Romanchuk, Dwayne Romanovich, William Rombough, Eduardo Romeo, Joy Romero, Claude Rondeau, Harvey Rosenkranz, Dennis Ross, Indra Ross, Robert Ross, Ron Ross, Graham Rosso, Worley Rosson, Barry Rosychuk, Cheryl Rosychuk, Rick Rosychuk, Roy Roth, Tom Roth, Katarina Rothe, Judy Rotzoll, David Rouleau, Gordon Rourke, Richie Rovere, Natasha Rowden, Scott Rowein, Andrea Roy, Beverly Roy, Jeff Roy, Zenita Ruda, Colleen Rudolph, Colleen Ruggles, Nigel Rusk, Denise Russell, Matthew Russett, Jeff Rutherford, John Rutherford, Brian Rutledge, Doug L. Rutley, Daniel Ruttan, Mark Rutter, Hal Rutz, David Ruud, Dan Ryan, Rick Rybchinsky, Craig Ryder, Jessica Rylaarsdam, Jeff Ryll, Mikael Sabo, Adam Saby, Gurdip Sahota, Poonam Saini, Darlene G. Sakires, Dwight Salahub, Mourad Salameh, Alba Salazar, Shahid Saleem, Peter Salomon, Gord Salt, Jennifer Sampson, Geoffrey Samuel, Juan Jose Sanchez, Andrea Sanden, David Sanderson, Michael Sanderson, Sandy Sandhar, Darryl Sandquist, Tom Sanelli, Juan Pablo Santini, Megan Santucci, Andrea SanVicente-Kraus, David Sargent, John C. Sargent, Carlos Sarmiento, Anita Sartori, Greg Sauer, Lisa Saumier, Jesse Savard, Christine Savary, Brian Saville, Codey Saville, Luc Savoie, Rajan Sawhney, William Sawyers, Chris Sayer, Richard Sayer, Amber Sayers, Kimberley Scagliarini, Christine Scammell, Ryan Scammell, Brian Scarth, Robert Schaap, Trevor Schable, Bruce Schade, Judy Schafer, Derek Schaffer, Paul Schaub, Lorne Schaufert, Perry Scheffelmaier, Barry Schellenberg, Mike Schellenberg, Lance Schelske, Curtis Scherger, Sally Schick, Larry Schielke, Mike Schiller, Ronald Schlachter, Marcus Schlegel, Helen Schlenker, Tracy Schmaltz, Beat Schmid, Jeannette Schmidt, Kimberly Schmidt, Raquel Schmidt, Joseph Schmitz, Melissa Schmitz, Christopher Schneider, Craig Schneider, Darryl Schneider, David Schneider, Debbie Schneider, Joseph Schneider, Luanne Schneider, Paul Schneider, Blaine Schnell, Craig Schnepf, Aaron Schnick, Jack Schnieder, Ronald Schnieder, C. Brian Schnurer, Rene Schoch, Stephen Schofield, Norm Schonhoffer, Tracy Schooler, Elka Schrijver, Jennifer Schroeder, Sheldon Schroeder, Michael Schubert, Tricia Schuh, Stephen Schultheiss, Randy Schultz, Kevin Schumacher, Lorraine Schwetz, Tony Sciarrabba, Leslie Scory, Curtis Scott, Drew Scott, James Scott, John Scott, Murray Scott, Ronalda Scott, Rodney Scoville, Ashley Scriba, Neil Scully, Gordon Seabrook, Geordie Seaton, Adam Seber, Don Sedor, Brian Segouin, Morley Seguin, Stephen Seguin, Linda Sehn, Clayton Seifridt, Paul Seipp, Fraser Selfridge, Mike Sell, Kenneth Selman, Leslie Semeniuk, Roland Senecal, Debbie Sereda, Edward Serniak, Cindy Severite, Jeremy Seward, Gianni Sgambaro, Mohsen Shafizadeh, Sanjay Shah, Aqeel Shakir, Philip Shankowski, Gilbert Shantz, Raj Sharma, Brigitte Shaw, Lisette Shaw, Marilyn Shaw, Dorothy Shea, David Sheaves, Wayne Sheaves, Ben Shenton, Glenn Sheppard, Robert Sheppard, Judi Shermerhorn, Jason Sherstabetoff, Kyla Shideler, Annette Shillam, Bill Shmoury, Leonard Shostak, Robert Shumay, Trent Shwaluk, Morgan Sibley, Melanie Siddon, Steve Siemens, Travis Siemens, Andrew Sikomas, Wayne Sikorski, Lorraine Silas, Beh Silue, Armindo Silva, Cam Simard, Kevin Simard, Francesca Simms, Bradley Simonar, Barbara Simpson, Brad Simpson, Gordon Simpson, Pat Simpson, Elisha Sinclair, Garry Sinclair, Robert Sinclair, Jerret Singer, Mackenzie Singer, Darcy Singleton, Paul Siree, Richard Sisson, Matt Skanderup, Kelly Skarra, Ashley Skiba, Geoffrey Skinner, Michael Skipper, Max Skliarov, Grace Skoczek, Shirley Skulmoski, Martin Skulski, Michael Skyrpan, Michelle Slater, Michael Slavin, Edward Sleet, Delwin M. Slemp, Darrell Sleno, Kevin Slotwinski, Doreen Smale, Lyle Small, David Smart, Bill Smith, Blair Smith, Bonnie Smith, Carl Smith, Catriona Smith, David L.M. Smith, Jessica Smith, Maurice Smith, Michael Smith, Nancy Smith, Robert Smith, Ryan Smith, Sandra Smith, Scott Smith, Tim K. Smith, Tina Smith, Todd Smith, V. Todd Smith, Allen Smyl, Brad Smylie, Jeffrey Snide, Robert Snihur, Kurt Snow, William Snow, Douglas Snyder, Kristine Snyder, Catherine Sobieski, Kristi Soderman, Angelina Solis, Ray Soon, Laurie Sopkow, Hans Sorensen, Curtis Sorochan, Daryl Soroko, Dallas Spagrud, Paul Spavor, Eddie Spearman, Jason Spears, Robert Spears, Gail Spence, Kevin W. Spencer, Darcy Spenst, David Spetz, David Spooner, John Springer, Mike Sprinkle, Ellis Spurrell, Lawson Squire, Murugan Srinivasan, Robert St.Amant, Richard St.Martin, Robert St.Martin, Mario St.Pierre, Megan Stables, Carrie Stacey, Ian Stacey-Salmon, Randy Stadnyk, Stacey Stadnyk, Tyson Stafford, Kendall Stagg, Rodney Stahn, Mark Stainthorpe, Karen Stairs, Ernesto Stamile, Randy Stamp, Nick Stanford, Michael Stang, Jason L. Starchuk, Lezlie Stark, Christie Starnes, Vicki Starr, Justin Stastook, Scott Stauffer, Scott Stauth, Achilles Stavropoulos, Craig Steel, Mark Steenbergen, Leanne Steeves, Gary Stefan, Jerry Stefanyshyn, Wayne Steffen, Robert Steinborn, Carolyn Steinson, Peter Stephen, Taryn Stephenson, G. Austin Stevens, Lyle Stevens, Robert Stevenson, Carol Stewart, Don Stewart, Douglas Stewart, Lorie Stewart, Rory Stewart, Wendy Stewart, Kevin Stilwell, Stewart Stirling, Melissa Stockes, Lindsey Stockley, Mark Stockton, Eric StPierre, Suzanne Strachan, Wade Strand, Robert Strang, Linda Strangway, Tanner Strangway, George Stratford, Brenda Stratichuk, Michael Street, William Stretch, Matthew Stroh, Michael Stroh, Brianna Stromberg, Sherry Struck, Robert Struski, Cory Struth, Dwayne Strynadka, Linda Stuart, Allan Stubel, Paul Stuckey, Mike Sturkenboom, David Sturrock, Ravi Subramaniam, Stephen Suche, Justin Sullivan, Mark Sullivan, Shelley Sullivan, Shiraz Sumar, Effie Summers, Daniel Sutherland, Laura Sutherland, Scott Sverdahl, Rade Svorcan, Michael Swain, Adam Swallow, Christine Swan, Rick Swanson, Nathan Swennumson, Halina Swierz, Don Sylvestre, Catherine Szmata, Vicky Ta, Darren Taciuk, Marlin Taillefer, Dave Talbot, Miguel Tamayo, Kevin Tanas, J. 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Tenold, Stephen Terry, Gus Teske, Jason Tessier, Terence Tham, Michelle Thares, Richard Theberge, Jean-Paul Theriault, Marc Theroux, Laureen Thiele, Chad Thiessen, Chris Thiessen, Karen Thistleton, Laurie Thomas, Angela Thompson, Arthur Scott Thompson, Ben Thompson, Chris Thompson, Gerald Thompson, Herb Thompson, Ian Thompson, Mark Thompson, Mindy Thompson, Ryan Thompson, Peter Thomsen, Adele Thomson, Julie Thomson, Todd Thomson, Bruce Thornton, Keith Thornton, Jason Thurlow, Andrea Thurmeier, Margaret Thurmeier, Daniel Tillapaugh, Joseph Tiller, Sandra Tillier, Terry Tillotson, Colin Tiltman, Brian Timmerman, David Timms, Simon Timothy, Bruce E. Tipton, Dharmendra Tiwary, Eric To, Carol Tobin, Ron Tochor, James Todd, Akindele Tododo, Mervin Todoschuk, Al Tokarchik, Alfred Tokpa, Chris Tomlinson, Dale R. Tomlinson, David Tonner, Domenic Torriero, Chyndelle Toth, David Toth, Paige Tracey, Sabrina D. Trafiak, Maurice Tremblay, Catherine Trenouth, Brian E. Trimble, Ray Trombley, Len Trotzuk, Sherry Truman, Michael Truong, Ruari 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, Stanley Turner, Darren Turpin, Veronika Turska, William Tustian, Irene Tutto, Cary Twardy, Dave Tweddell, Kelly Tweten, Oleg Tyan, Wayne Tymchuk, Shaun Tymchyshyn, Kathleen Tynan, Kenechukwu Ufondu, Eric Ulrich, Gregory A. Ulrich, Janis Underdahl, Nathan Underwood, Karl Unger, Jackeline Urdaneta, Roger Vachon, Anand Vaidyanath, Allan Valentine, Darrel Valin, Gary L. Valiquette, Louis Vallee, Michael Vallee, Helene Vallieres, Vyvette Vanderputt, Christina VanderPyl, Timothy vanGoudoever, Bryant VanIderstine, Hennie vanNiekerk, Salomon VanRensburg, Collin Vare, Daniel Vasseur, Nicolette Vaughan, Laureen Vaughan-Kirk, Sheila Verigin, Natalia Verkhogliad, Dan Verleyen, Nancy Tay Vetrici, Cesar Viana, Dale Vickery, Wilf Vielguth, Marvin (Joe) Viola, Tony Vitkunas, Demetry (Jim) Vlahos, James W. Vollman, Mel Vollman, Leo Vollmin, Luke Vondermuhll, Kyle Waddy, Todd Waggoner, Trevor Wagil, Joy Wagner, Juon Wah, Lee Wahl, Robert N. Waites, Donald Wakaruk, Michael Lane Wakefield, Kevin Wakulchyk, Ken Walchuck, Jeff Walden, Dave Waldner, Darcy Waldo, Sara Waldo, Carolyn Walker, David Walker, David Walker, Martin Walker, Erin Wallace, Greg Wallace, Kevin Wallace, Marie Wallace, Vince Wallwork, Lorie Walter, Michelle Walton, Roger Walton, Alfred Wandler, John A. Wandler, Blaise Wangler, Tim Wanner, Kathy Ward, Kirk Ward, Terry Ware, Wayne M.J. Warholik, Chris Wark, Wanda Warman, John Warrell, Colin Warren, Michael Warrick, Ajit Warrier, Faye Warrington, Paul T. Wassell, Godfried Wasser, James Waterfield, Frank Watkin, Julie Watkins, Kay Watson, Ken Watson, Graham Watt, John Watts, Trish Wear, Alan Webb, Byron Webb, Larry Webb, Kent Weber, Keith Webster, Gail Wee, Eric Weening, Carlee Wehrhahn, Jeff Weibrecht, Lionel Weinrauch, Randy Weir, Brock Weisgerber, Adrian Weleschuk, Guy Welwood, Mark S. Wenner, Dwayne Werle, Craig Werstiuk, Matthew Werstiuk, Ted Wesley, Darrin West, Jacqueline West, Michael Westad, Terry Wetzstein, Nina Whalen, John Wham, Terence Whang, Loyd Wheating, Joshua Wheaton, Andrew Wheeler, Charmaigne Whelan, Chris Whelan, Rosemarie Whelan, Daniel White, Debbie White, Francis W. 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Bill Wong, Jason Wong, Jennifer Wong, Linda Wong, Lisa Wong, Julie Woo, E. Bette Wood, Leonard Wood, Philip Wood, Roxanne Wood, Laura Wooding, Travis Woods, Marilyn Woodske, Wayne Woodward, Robin Woolner, Sidney Wosnack, Raymond Wourms, Mark Woynarowich, Chris Wright, Daniel Wright, Richard Wright, Stephen Wright, Bin Wu, Christine Wutzke, Brent Wychopen, Guy Wylie, George Wyndham, Brent Wyness, Barry Wynne, Valerie Wyonzek, Canghu Yang, Zhen Lin Yang, Andrew Yaremko, Rick Yarmuch, Teddy Yarmuch, James Yaroslawsky, Jeff Yates, Noah Yates, Basile Yeboue, Betty Yee, Davin Yee, Michael Yee, Claire Yeoman, Michael Yeoman, Jeffrey Yip, Kitty Yip, Tony Yip, Mark Yobb, Amber Yoingco, Darrell York, Rachelle Yorke, Daryl Youck, Chalene Young, Clayton Young, Lynn Young, Michael Young, Ray Yowney, Eugene Yu, Jian-Yang Yuan, Clement Yuen, Dustin Yuill, Jeff Yuill, William Yuill, Brian Yurchyshyn, Robin Zabek, Robert Zabot, Gabriel Zachoda, Tyler Zachoda, Cam Zackowski, Attila Zahorszky, Devin Zaichkowsky, Domingo Zambrano, Mark Zan, Kendall Zarowny, Glenn Zeebregts, Lynn Zeidler, Diane Zeilznik, Tony Zeiser, Aleksandra Zelic, Darcy Zelman, Denis Zentner, Kathy Zerr, Michelle Zerr, Jessica Zhang, Xu (Frank) Zhang, Susan Zheng, Wanli Zhu, Evgeny Zhuromsky, Brenda Ziegler, Dwayne Zilinski, Megan Zilkey, Hernando Zorrilla, Aaron Zubot, Ana Zulueta

Review of Operations

TIM S. McKAY,
SENIOR VICE-PRESIDENT, OPERATIONS

MARY-JO E. CASE,
VICE-PRESIDENT, LAND

Production Strategy and Results

In 2006, Canadian Natural's defined strategy continued to deliver; our production and reserves grew significantly as they have each and every year since 1989. Through the last 18 years, we have adhered to the same defined business strategy of maintaining large project inventories in every product and basin in which we operate. Large project inventories enable the Company to continually high-grade the capital allocation process and balance production mix among 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.

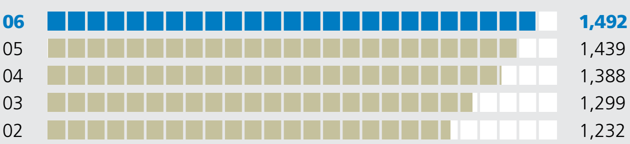
In 2006 we again achieved record levels of production on a barrels of oil equivalent basis. Production before royalties was 581 mboe/d during 2006, up 5% from 2005 levels and was achieved through a combination of exploration, asset development, and the acquisition of ACC. Natural gas production before royalties increased by 4% and continues to represent our largest product offering. Total crude oil and NGLs production before royalties increased by 6%, with the primary drivers being a full year's benefit of production from the Baobab Field located offshore Côte d'Ivoire, the commencement of production from the Primrose North expansion project and the continued improvements to Pelican Lake EOR performance.

Strategic Land Base

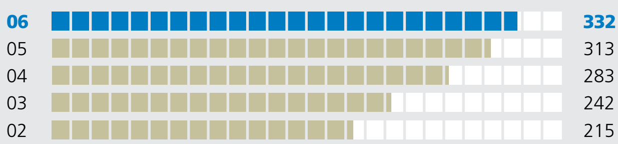
Canadian Natural has the largest undeveloped land inventory in the Western Canadian Sedimentary Basin ("WCSB"), with undeveloped net acreage totaling 12.8 million net acres. Total WCSB landholdings were 19.2 million net acres at the end of 2006, up significantly, 16%, from 2005, as a result of continued land purchases and the acquisition of ACC. This strong concentrated land base affords significant opportunities to control our operating costs, and finding and onstream costs. The vast majority of our land base is positioned to utilize existing owned and operated infrastructure and it also strategically positions us to maximize the benefit of new play types

	2006		2005	
	Production	**Mix**	Production	Mix
(before royalties)	mboe/d	%	mboe/d	%
Natural gas	**249**	**42**	240	43
North America light/medium crude oil and NGLs	**51**	**9**	52	10
Pelican Lake crude oil	**29**	**5**	23	4
Primary heavy crude oil	**91**	**16**	93	17
Thermal heavy crude oil	**64**	**11**	53	10
North Sea light/medium crude oil	**60**	**10**	69	12
Offshore West Africa light/medium crude oil	**37**	**7**	23	4
Total	**581**	**100**	553	100

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



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



CORE LANDHOLDINGS

(thousands of acres)	2006 Gross	2006 Net	2006 %	2005 Gross	2005 Net	2005 %
North America						
Developed	8,062	6,366	79	7,184	5,699	79
Undeveloped	15,848	12,785	81	13,163	10,947	83
	23,910	19,151	80	20,347	16,646	82
North Sea						
Developed	138	93	67	138	93	67
Undeveloped	367	299	81	457	352	77
Offshore West Africa						
Developed	7	4	57	7	4	58
Undeveloped	247	207	84	521	426	82
Total						
Developed	8,207	6,463	79	7,329	5,796	79
Undeveloped	16,462	13,291	81	14,141	11,725	83
	24,669	19,754	80	21,470	17,521	82

developed by ourselves and industry.

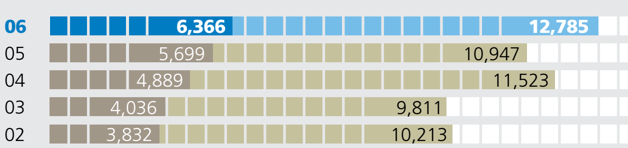
The infrastructure associated with this vast, concentrated land base also provides a competitive advantage in terms of lower marginal operating and development costs for newly drilled or acquired properties. This dominance can create acquisition opportunities, as we maintain a low-cost regime and access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

Geo-Science Strategy

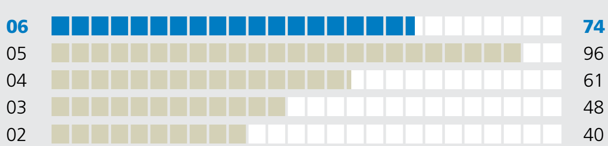
We believe that a multi-disciplined focus on geology, geophysics and reservoir engineering reduces exploration risk and ultimately results in better full cycle economics. Integrating the seismic interpretation with geology and innovative engineering results in our successful annual drilling program and adds new high quality locations to our conventional and unconventional inventory. In Canada, we invested $74 million during 2006 to acquire new seismic and to purchase and reprocess existing seismic data. In total, 3,667 kilometers of conventional 2D seismic data and 228 square kilometers of 3D seismic data were acquired. Additionally, 9,469 kilometers of conventional 2D seismic data and 437 square kilometers of 3D seismic data were purchased. We continue to acquire this data under stringent environmental controls and in a cost effective manner. The ACC acquisition resulted in adding 394 kilometers of 2D seismic data and 23,000 square kilometers of 3D seismic data to our database.

In the North Sea, we purchased 739 square kilometers of 3D seismic and reprocessed a further 1,210 square kilometers of 3D seismic data. This data allows us to continue aggressive in-field and near-field development and exploration. In Offshore West Africa we purchased 3,796 kilometers of 2D seismic data and acquired 168 kilometers of electromagnetic seabed data to help confirm seismic prospects.

Total North America landholdings (thousands of net acres)



Seismic expenditures in Canada ($ millions)



Review of Operations (continued)

DOUGLAS A. PROLL,
CHIEF FINANCIAL OFFICER,
SENIOR VICE-PRESIDENT, FINANCE

RANDALL S. DAVIS,
VICE-PRESIDENT,
FINANCE & ACCOUNTING

ACTIVITY BY CORE REGION

	Net Undeveloped Land (thousands of net acres)		Drilling Activity (net wells)	
	2006	2005	**2006**	2005
Canadian conventional				
Northeast British Columbia	**2,721**	2,027	**196**	241
Northwest Alberta	**1,750**	1,507	**194**	183
Northern Plains	**6,804**	6,238	**728**	711
Southern Plains	**870**	621	**120**	354
Southeast Saskatchewan	**117**	82	**75**	52
In-situ Oil Sands	**407**	356	**247**	196
	12,669	10,831	**1,560**	1,737
Horizon Oil Sands Project	**116**	116	**163**	126
United Kingdom North Sea	**299**	352	**9**	14
Offshore West Africa	**207**	426	**6**	5
	13,291	11,725	**1,738**	1,882

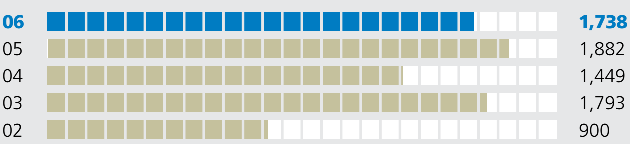
Drilling Activity and Strategy

In 2006, high demand resulted in increased costs for drilling and related activities; coupling this with the inefficiencies of an overheated service sector created a very unfavorable cost environment for organic growth. Strong demand resulted in low service crew efficiencies partially due to utilizing less experienced personnel. This was combined with an unusually warm start to the winter drilling season and the resultant aggressive attempts to complete the program before the onset of spring breakup.

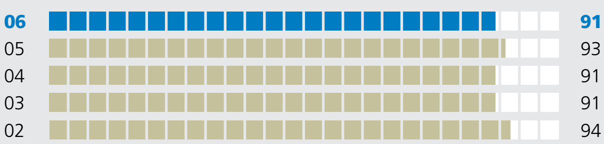
By May 2006, we made the strategic decision to reduce capital spending on natural gas drilling activities due to exceedingly high service costs in Western Canada. The result was a 17% reduction in total drilling activity, excluding service and stratigraphic test wells. We still maintained a drilling success rate of 91% reflecting the low-risk exploitation approach that we take to the business.

For 2007 we plan to further reduce drilling activity by 19%, in response to continued cost pressures in the basin and to balance capital spending in light of the 2006 acquisition of ACC.

Total net wells drilled



Drilling success rate, excluding stratigraphic test/service wells (%)



WELLS DRILLED

Year Ended December 31	2006			2005	
	Gross	**Net**	**Success**	Net	Success
Crude oil – North America					
Light crude oil	**140**	**113**	**92%**	81	92%
Pelican Lake crude oil	**144**	**144**	**100%**	83	99%
Primary heavy crude oil	**301**	**274**	**94%**	341	94%
Thermal heavy crude oil	**66**	**60**	**98%**	107	98%
North Sea light crude oil	**8**	**8**	**100%**	12	87%
Offshore West Africa light crude oil	**7**	**4**	**100%**	3	85%
	666	**603**	**95%**	627	95%
Natural gas – North America					
Northeast British Columbia	**185**	**163**	**90%**	201	88%
Northwest Alberta	**192**	**155**	**88%**	152	92%
Northern Plains	**286**	**219**	**84%**	199	84%
Southern Plains	**192**	**104**	**93%**	338	99%
	855	**641**	**88%**	890	91%
Dry	**133**	**119**		117	
Subtotal	**1,654**	**1,363**	**91%**	1,634	93%
Stratigraphic test / service wells	**376**	**375**		248	
Total	**2,030**	**1,738**		1,882	

North American crude oil drilling remained strong with over 600 wells drilled, essentially flat with 2005 levels. This reflected the superior recycle ratios experienced on heavy crude oil during 2006 as well as better cost control capability for this activity. These heavy crude oil drilling activities benefit from lands which are generally accessible year-round, larger scale programs which generate efficiencies and the requirement for fewer ancillary services than natural gas drilling.

During 2006, 163 net stratigraphic wells were drilled on our oil sands mining leases and 181 were drilled on our thermal in-situ oil sands leases to delineate resource potential and better define the Company's growth opportunities. Additionally a total of 31 net stratigraphic and service wells were drilled, including 27 wells in Canada and 4 internationally.

Marketing

**RÉAL M. CUSSON,
SENIOR VICE-PRESIDENT,
MARKETING**

Natural Gas

Canadian Natural's gas marketing objective is to maximize the realized price for its overall portfolio. Our strategy is predicated on the development of solid business relationships based on demonstrated performance and integrity, and 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 19% of direct sales to various American customers, 71% 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 concerned parties.

Canadian Natural's realized wellhead price in 2006 was 22% lower than in 2005 at $6.77/mcf primarily due to very warm winter weather across North America which resulted in strong natural gas inventories all year. The natural gas storage positions are expected to close the withdrawal season at the end of March 2007 at levels close to those seen in 2006. Drilling activity in the US was very strong in 2006 with a record number of completions at 29,356 whereas in Western Canada, we experienced the first yearly reduction in completions since 2002 at 15,362. However, the North American overall demand was essentially flat year over year with the increase in the electrical generation offset by the losses from the industrial sector.

We expect the North American supplies to be challenged in the near term as the industry needs to become more efficient to contain its costs. The reduction in gas directed drilling activities started in late 2006 and is continuing in the first quarter of 2007, which should result in significantly lower yearly production volumes for the industry in 2007. The longer term prospects look very positive for the gas business as it is increasingly challenging to bring large incremental quantities to markets. The large number of proposals to import liquefied natural gas in the North American grid has yet to translate into incremental quantities available to the end users with the 2006 import volumes remaining flat at 1.8 bcf/d. The forecast is for a modest increase of these volumes in 2007 as the competition for supplies intensifies with European and Asian markets.

Canadian Natural's natural gas production for 2007 is forecast to average between 1,594 - 1,664 mmcf/d and with the current 2007 pricing strips for NYMEX at US$7.60/mmbtu and AECO at C$7.57/GJ, this would yield an overall wellhead price of C$7.90/mcf for our sales portfolio, using a US$0.86/C$1.00 exchange rate.

WTI crude oil reference pricing (US$/bbl)

06	**66.25**
05	56.61
04	41.43
03	31.02
02	26.11

NYMEX natural gas reference pricing (US$/mmbtu)

06	**7.26**
05	8.56
04	6.09
03	5.44
02	3.25

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 consist 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.

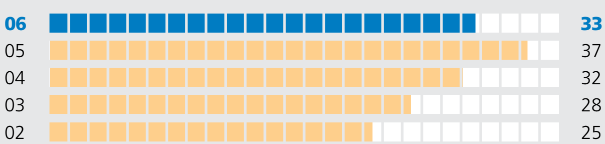
Canadian Natural's realized wellhead price increased by more than 15% in 2006 to $53.65/bbl mainly based on the strong worldwide demand for hydrocarbons and a constrained supply environment with practically no spare capacity from the producers and full utilization of worldwide refining assets. The benchmark price for WTI crude oil was up 17% in 2006 to US$66.25/bbl and hit an all time high of US$78.40/bbl on July 14 primarily in response to the political turmoil in the Middle East. Brent crude oil was also higher than in 2005 by 20% to US$65.18/bbl based on strong European and Asian demands. The price differential for the Lloyd Blend heavy crude oil improved by 4% over 2005 at 33% of the WTI benchmark. The stronger commodity prices were somewhat offset by a Canadian currency that was 6% stronger in 2006.

Canadian Natural continued to successfully implement its blending strategy in 2006 and contributed 53% of the total 257 mbbl/d of WCS stream in the fourth quarter. The second phase of the marketing strategy entails geographic expansion of pipeline systems to open new markets for heavy crude oil. The logistical challenges are being addressed by industry and significant progress was achieved in 2006 with the new service on the Spearhead and Pegasus pipelines to reach the Southern PADD II refining markets. These expansions had a very positive impact on heavy crude oil differentials over the last nine months of 2006.

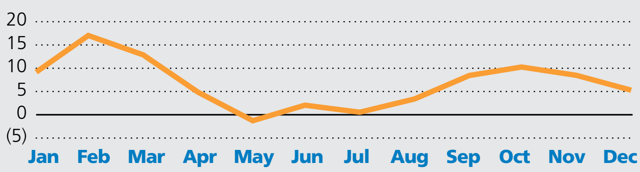
In the future, several pipeline projects are being developed to transport crude oil from the WCSB to the West Coast, Eastern PADD II and Southern PADD II with access to the US Gulf Coast refineries. In particular, the Enbridge Southern Access Pipeline expansion is scheduled to add 394,000 bbl/d to the greater Chicago market area by 2009 and the Terasen TMX 1 project to add a total of 75,000 bbl/d to the West Coast by 2008. The TCPL Keystone project, which could add 435,000 bbl/d to the Woodriver and Patoka market area, has received the approval from the National Energy Board to transfer a gas pipeline to the oil service. Keystone has filed its application to build the facilities and is currently conducting an open season on its option to extend its proposed pipeline to Cushing with an ultimate capacity of 590,000 bbl/d. We are 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 specifically from the oil sands projects.

Canadian Natural continues to work with North American refiners to encourage the addition of conversion capacity to their facilities and has committed a volume of 25,000 bbl/d for 5 years to a proposed upgrading facility to be built in Sturgeon County, Alberta by 2010. With respect to efforts to build an upgrader for our in-situ operations, engineering studies completed in early 2007 identified growing concerns relating to increased environmental

LLB price differential to WTI (%)



Mayan - LLB spread (US$/bbl)



Marketing (continued)

costs for upgraders built in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, and as a result deferred ongoing design work pending clarification on the cost of future environmental legislation and a more stable cost environment.

Canadian Natural's portfolio for 2007 is targeted to average between 315,000 bbl/d and 360,000 bbl/d and based on the current 2007 pricing strips for WTI at US$60.38/bbl would yield an overall wellhead price of C$50.67/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 in conjunction with commodities.

In conjunction with approval of the Horizon Project, our Board of Directors granted management the authority to hedge 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, the 15% interest in the Cold Lake Pipeline system, the 62% interest in the operated Pelican Lake Pipeline and the 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 and generate additional revenues from third party volumes and 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. In 2006, we completed the Morgan lateral at a cost of $6 million which helped in achieving 89% utilization rate on our ECHO Pipeline.

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

06	**1.13**
05	1.21
04	1.30
03	1.40
02	1.57

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

06	**6.72**
05	8.57
04	6.50
03	6.21
02	3.77

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

06	**53.65**
05	46.86
04	37.99
03	32.66
02	31.22

Health and Safety, Environment and Community

A commitment to "doing it right"

At Canadian Natural, our people and our contractors have a vision for health and safety, environment and community. We are committed to responsible operations, and to "doing it right". We have systems in place and have set targets for continuous improvement and measure our performance on an ongoing basis. As we enhance our health and safety, environment and community programs, we also work to meet the expectations our stakeholders and communities have around corporate citizenship.

Health and Safety: working for continuous improvement

We conduct our operations in a manner that protects the health and safety of employees, contractors, the public and the environment. Our ongoing focus on safety programs and processes, enhanced safety awareness throughout our operations, and the high degree of co-operation with our contractors is essential to achieve continuous improvement.

In 2005 we obtained our Certificate of Recognition ("COR") through Enform which is a certifying partner of Alberta Workplace Health and Safety and the Workers' Compensation Board of British Columbia. As part of our COR maintenance program in 2006, we continued our internal audit program, conducting more than 500 facility, drilling and service rig, pipeline and construction project audits.

In 2006 our conventional operations team updated its Comprehensive Safety Manual and Employee Guide to Accident Prevention, and re-emphasized the role each person plays in ensuring a safe work environment. In our North American conventional operations, total lost time accident frequency and total recordable injury frequency declined in 2006, continuing a downward trend over the past four years.

As part of a pilot program conducted by the Alberta Energy and Utilities Board ("EUB"), Canadian Natural was selected to undergo a comprehensive assessment of our emergency response capabilities in 2006. A rigorous process was used by the EUB to test our emergency response plans and our ability to activate our plans. The results of the assessment identified no major deficiencies and demonstrated our strong response capability.

Internationally, we continued to develop and implement our enhanced Safety Health Environment Management System ("SHEMS"). Lost time injuries dropped by more than 20% from 2005. The total recordable injury frequency rates also improved by 18% compared to 2005 results.

As activities accelerate at our Horizon Project, overall safety performance, as measured by our total recordable injury frequency has improved throughout 2006, building on excellent performance in 2005. Incident exposure hours increased in 2006 to 5.8 million as compared to 3 million in 2005. Our new near-miss incident campaign has contributed to continuous improvement. The Horizon Project also conducted construction safety field audits for major contractors on-site, developed plans for 2007 audits, and launched a fully functional Emergency Operations Centre. As we progress towards commissioning in 2008, work continues on our safety training programs and processes for employees and contractors, and the integration of our emergency response plans with those of the local municipal district.

Health and Safety, Environment and Community (continued)

Integrity: working together for best practices

In 2006, each of our divisions worked together to identify common key performance indicators and best management practices that solidify our commitment to integrity. All three divisions have developed strong integrity groups and have brought together standard benchmarks used to track quality.

Environment: focus on stewardship

Canadian Natural's environment group continues to work together with management and operating personnel to ensure that environmental stewardship is factored into all aspects of our operations. Training and due diligence are key to our environmental management programs, and we continue to increase our investment into environmental management strategies such as air emission management, reduction of fresh water use and minimization of our landscape footprint.

In our conventional operations and at our Horizon Project site, initial development of our enhanced Environmental Management System ("EMS") was undertaken in 2006. The primary focus of the EMS is to ensure our field operations minimize their environmental impact and meet all regulatory requirements and corporate standards. EMS awareness training was developed and delivered to employees. Training will continue into 2007 to ensure our high level of environmental, stakeholder and sustainability performance is maintained.

With plans for operational start-up only two years away, the Horizon Project implemented several programs in 2006, including: environmental monitoring programs for soils, fisheries and water quality; a weekly environmental inspection program of construction sites; and, a wildlife management procedure. Development of other programs continue, including an environmental records management system, as well as commissioning and start-up monitoring programs.

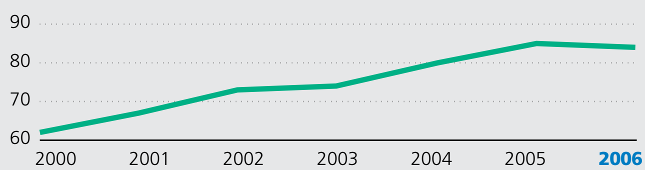
Work is ongoing to continue to reduce our long-term fresh water use, including increasing use of brackish saline water for our in-situ operations, and recycling a high percentage of produced water. In Canadian Natural's thermal operations, our water recycle

rate is greater than 95%. Increased brackish saline water use at our Primrose and Wolf Lake operations over the past two years has enabled increased bitumen production without an equivalent increase in fresh water use.

Canadian Natural is committed to managing air emissions through an integrated corporate approach which considers opportunities to reduce both air pollutants and greenhouse gas ("GHG") emissions. Air quality programs continue to be an essential part of our environmental work plan and are operated within all regulatory standards and guidelines. Our strategy for managing GHG emissions is based on four core principles: energy conservation and efficiency; reduced intensity; innovative technology and associated research and development; and, emissions trading capacity; both domestically and globally.

We continue to implement flaring, venting and fuel and solution gas conservation programs. In 2006 we completed approximately 122 gas conservation projects, resulting in the reduction of 1.24 million tonnes/year of carbon dioxide equivalents ("CO_2E"). Over the past five years we have spent over $100 million to conserve the equivalent of over 5 million tonnes of CO_2E. In our heavy crude oil production areas we are evaluating tank heater efficiencies in an effort to conserve fuel gas at facilities with field tanks. We also

Solution gas conservation rate (%)



monitor the performance of our compressor fleet and it is continually modified and optimized for maximum efficiency. Another project of note is the trial of "no-emissions" chemical injection pumps which will eliminate fuel gas venting.

These aggressive programs also influence and direct our plans for new projects and facilities. The Horizon Project will incorporate numerous advancements in technology which will result in the reduction of GHG emissions. The key to GHG reductions at Horizon is a focus on maximizing heat integration, the use of cogeneration to meet steam and electricity demands and the design of the hydrogen production facility to enable carbon dioxide ("CO_2") capture.

At our North Sea operations, we are operating below our CO_2 allocation, and we continue to implement an improvement program based on efficiency audits of our major facilities. We also began a Produced Water Re-Injection trial on one of our offshore platforms, successfully re-injecting about 30,000 barrels of produced water each day.

Community: developing people to work together

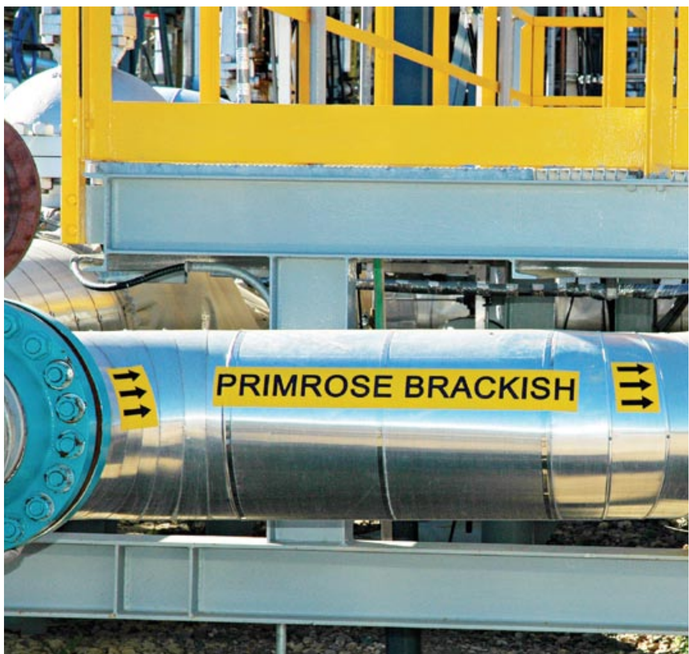
Canadian Natural is committed to a long-term presence in the communities where we operate. We are proud to work with our communities to provide financial and volunteer support for hundreds of projects that meet their vision for the future, contribute to the development of people, and to the building of strong communities.

In 2006, we met with stakeholders on a regular basis to update them on our operations and our commitments, to build trust and mutual respect, and to incorporate feedback into operations developments. In North America, we work closely with over 50 Métis and First Nations communities near our operations to strengthen mutual understanding and co-operation and enhance the opportunities for economic participation in our developments.

To help fulfill our mission statement "to develop people" and build capacity in communities where we operate, we launched our Building Futures Scholarship Program in 2002 to encourage training in our industry. To further expand the pool of skilled workers within Canada, we are developing an on-site apprenticeship training centre at our Horizon Project and have actively participated in many career fairs and contractor meetings throughout North America.

A range of multi-stakeholder groups are working to proactively address the needs and interests of the communities we operate in, and to ensure a sustainable energy industry. Recognizing the importance of these groups in achieving collaborative goals identified among industry, governments and communities, Canadian Natural continues to play an active role in many such initiatives where we do business.

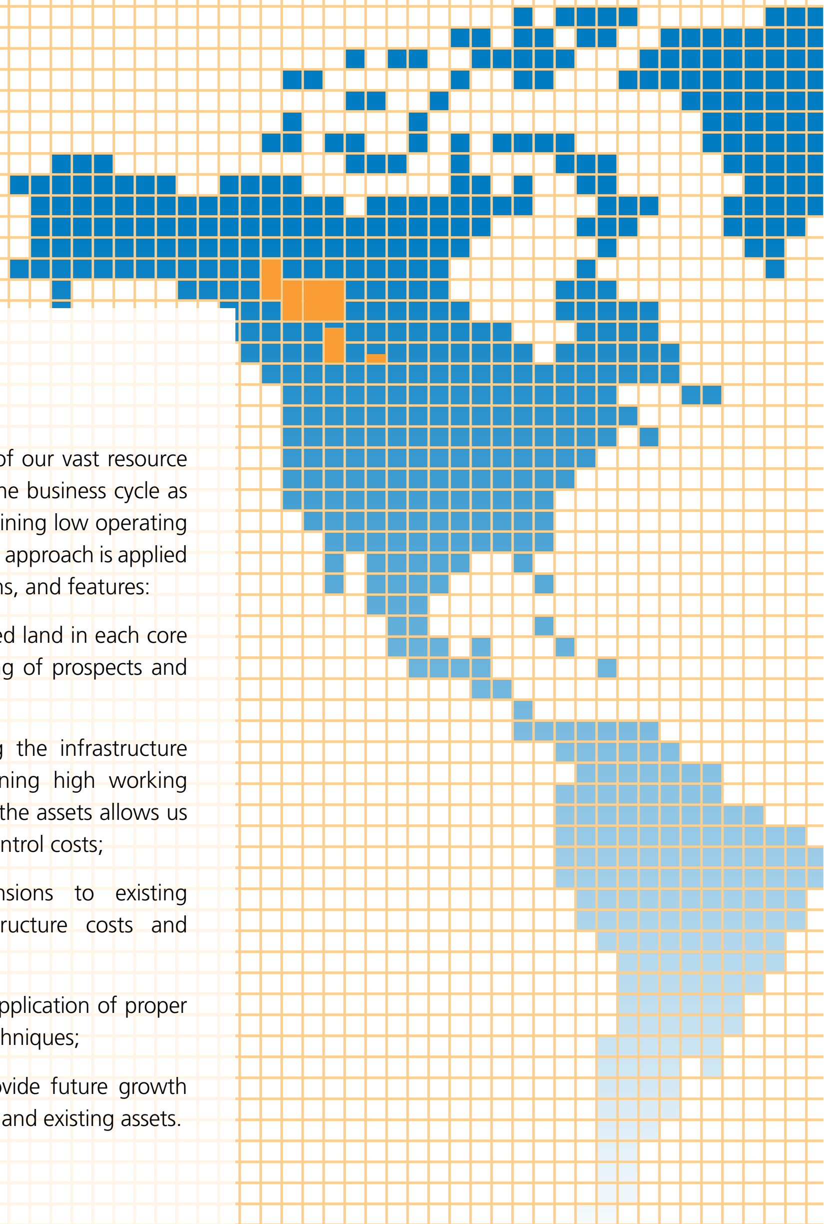
Highlights of our community investments in 2006 involved a wide range of projects such as the new community arena in Cold Lake, Lakeland College's Heavy crude oil Operations Technician academic wing in Lloydminster, new medical equipment for the Grande Prairie hospital, a new training centre in northeastern BC, and support for the Northern Lights Regional Health Foundation in Fort McMurray. In our International operations, we continued funding for a variety of community initiatives such as the Aberdeen Football Youth Academy, Childline Scotland and the Castle Hill Oncology Heath Centre. Canadian Natural's community sponsorship and donations funding support totaled more than $4.4 million in 2006.



The Assets

LYLE G. STEVENS,
SENIOR VICE-PRESIDENT,
EXPLOITATION

JEFF W. WILSON,
SENIOR VICE-PRESIDENT,
EXPLORATION



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-grading of prospects and optimizing 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;
- Pursuing opportunistic acquisitions that provide future growth opportunities and complement our expertise and existing assets.

North America

	2006 net results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Crude oil and NGLs	205	887
Natural gas	198	618
Boe	403	1,505
% of total	80	77

International

	2006 net results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Crude oil and NGLs	95	429
Natural gas	4	15
Boe	99	444
% of total	20	23

Horizon Project Mining

	2006 proved reserves	
	Gross lease (mmbbl)	Net (mmbbl)
Bitumen	2,275	1,853
SCO*	1,866	1,596

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

North American Natural Gas

North American natural gas remained Canadian Natural's single largest product, representing 42% of our equivalent production volumes. We are the second largest producer of natural gas in Canada with production of 1,468 mmcf/d in 2006. During 2006, average production volumes increased by 52 mmcf/d or 4%, reflecting our measured drilling and development program and the acquisition of ACC in the fourth quarter.

Production is concentrated in five North American core regions: Northeast British Columbia, Northwest Alberta, the Foothills, the Northern Plains and the Southern Plains. The large inventory of

opportunities that our focused area teams have developed and defined are expected to deliver 3-5% per annum production growth. On our existing land base we see the potential for more than 7,000 locations.

Northeast British Columbia

THE ASSET

Northeast British Columbia is one of the most highly prospective and relatively undeveloped regions in Western Canada. Canadian Natural's large undeveloped land base, 2.7 million acres, in conjunction with facility and pipeline infrastructure provides a significant competitive advantage. In this region natural gas is produced from an array of carbonate and sandstone reservoirs ranging from the shallow Notikewin at 2,000 ft to the deep Slave Point at 15,000 ft. The region has a mixture of low risk multi-zone targets, deep higher risk exploration plays and emerging unconventional natural gas plays including shale gas and Coal Bed Methane ("CBM").

2006 ACTIVITY

The Company drilled 193 net wells with an 90% success rate adding incremental production of 20 mmcf/d. At Helmet we continued development of the Jean Marie carbonate formation drilling 21 net horizontal wells and 12 vertical wells. Our larger programs included drilling 38 shallow Notikewin wells at Ladyfern and drilling 26 wells at Shekelie targeting the Banff formation.

WHAT TO EXPECT IN 2007 AND BEYOND

The drilling program in Northeast British Columbia is reduced in 2007 with only 56 wells planned as a result of an overheated service industry and a stronger focus on development of our crude oil assets. Post 2007, should cost pressures reduce, drilling activity is forecast to increase significantly to more than 200 wells per year, as we expand our defined prospect inventory and maximize the potential on the acquired ACC assets. We will continue to evaluate the emerging shale gas plays in the Muskwa and Wilrich shales and we are also looking to extend the promising Doig shale gas play from Northwest Alberta into Northeast British Columbia.

North American successful natural gas wells drilled
(net wells)

06	**641**
05	890
04	689
03	777
02	162

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

06	**1,468**
05	1,416
04	1,330
03	1,245
02	1,204

Northwest Alberta

THE ASSET

Northwest Alberta is a rich multi-zone crude oil and natural gas producing region. There are extensive exploitation opportunities as well as significant growth potential in unconventional natural gas from shale and tight sand. Canadian Natural's large undeveloped land base of 1.8 million net acres in conjunction with 26 operated facilities and an extensive pipeline network provides a significant competitive advantage.

2006 ACTIVITY

The Company drilled a total of 175 net natural gas wells, a 9 net well increase from 2005. We continued our low risk Cardium sand development, drilling 57 net wells with a 96% success rate. Canadian Natural has leveraged the Cardium project and our extensive infrastructure to develop the deeper, tight natural gas sands that exists in the region. In 2006 we drilled 28 deep wells for Mannville tight sand targets.

In the Peace River Arch region, the Company drilled 4 initial wells targeting Doig shale and also incorporated the ACC land to greatly expand Canadian Natural's exposure on this emerging unconventional play.

WHAT TO EXPECT IN 2007 AND BEYOND

The 2007 drilling program has been high graded to 118 net wells that are focused on Cardium, Deep gas, Doig and other conventional targets. These projects can support the drilling of over 1,100 locations in the next five years. Significant unconventional resource potential can be developed as a result of technology innovation, cost control, continued downspacing and ACC's substantial undeveloped land base.

Northern and Southern Plains

THE ASSET

Natural gas in the Northern and Southern Plains core regions is produced from shallow, low risk, multi-zone conventional exploitation prospects and in some regions natural gas is produced from the Horseshoe Canyon coals. This is generally considered a mature operating region. However, through ongoing focused exploitation we continue to find excellent prospects for new pool development, infill drilling and secondary zone recompletions. The success of CBM production from the Horseshoe Canyon coals has created a new economic low risk development opportunity which Canadian Natural continues to expand and the Mannville coals in the region represent new potential which we are now evaluating. This new development augments our significant shallow gas assets which contribute approximately 30 mmcf/d of the area production and provide the majority of the drilling inventory.

Our strategy in this region is to target low risk exploration and development opportunities on our extensive land base, examine synergistic property acquisitions opportunities, and minimize operating costs through high utilization of facilities and operations discipline.

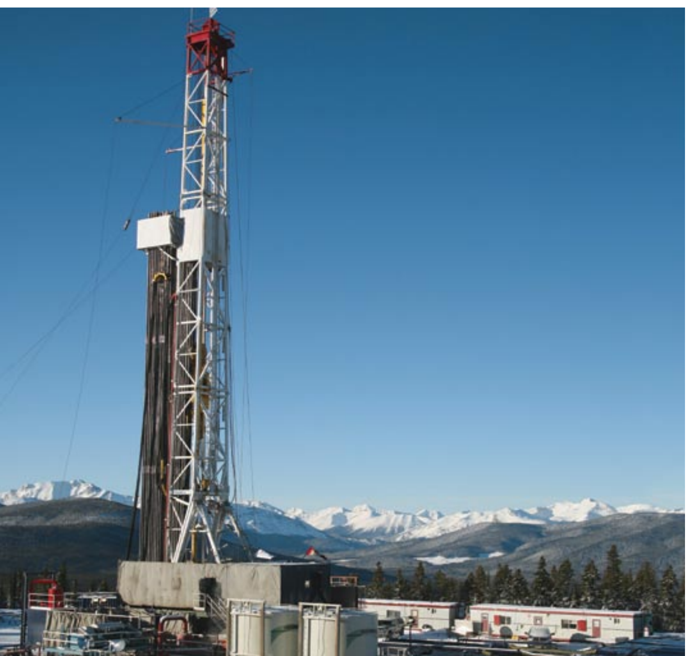
North American Natural Gas (continued)

2006 ACTIVITY

During 2006, 375 net wells targeting natural gas were drilled in the region with an 86% success rate. CBM development drilling continued to grow with the drilling of 48 net wells targeting the Horseshoe Canyon and we have also initiated a pilot project with three horizontal wells in Swan Hills to determine the economic potential of CBM production from the Mannville formation. A modest shallow gas drilling program was pursued in 2006 with 67 net wells drilled.

WHAT TO EXPECT IN 2007 AND BEYOND

The 2007 drilling program is comprised of more than 240 net wells, targeting low risk, shallow natural gas. CBM and conventional wells are planned as the Company continues to expand both its expertise and its commercial CBM operations. Our five year drilling inventory totals more than 3,620 net natural gas wells, including over 1,750 shallow locations and over 575 net CBM wells. With the addition of new shallow gas prospects through the ACC acquisition and continued Horseshoe Canyon CBM development we are forecasting modest production growth in the Northern and Southern Plains over the next five years.



Foothills

THE ASSET

Canadian Natural has both developed and significant undeveloped assets located in the Southern Foothills of Northeast British Columbia and in the North Central Foothills of Alberta. Gas production occurs in thrusted, structurally deformed Mississippian and Triassic aged reservoirs. Potential for high impact discoveries exists on most of our extensive land base.

2006 ACTIVITY

Canadian Natural Foothill's drilling program had exceptional results in 2006, drilling 4.7 net wells with a 100% success rate. Three new pool discoveries were made in the Murray River area and successful development wells were drilled at Copton, Dinosaur, Ojay and Cabin Creek. First production came on stream at our Copton and Dinosour properties from discoveries made in previous years. The ACC acquisition resulted in a significant growth of our Foothill assets, adding production and undeveloped lands in the very prospective regions of Monkman, Ojay, Sullivan Creek and Voyager.

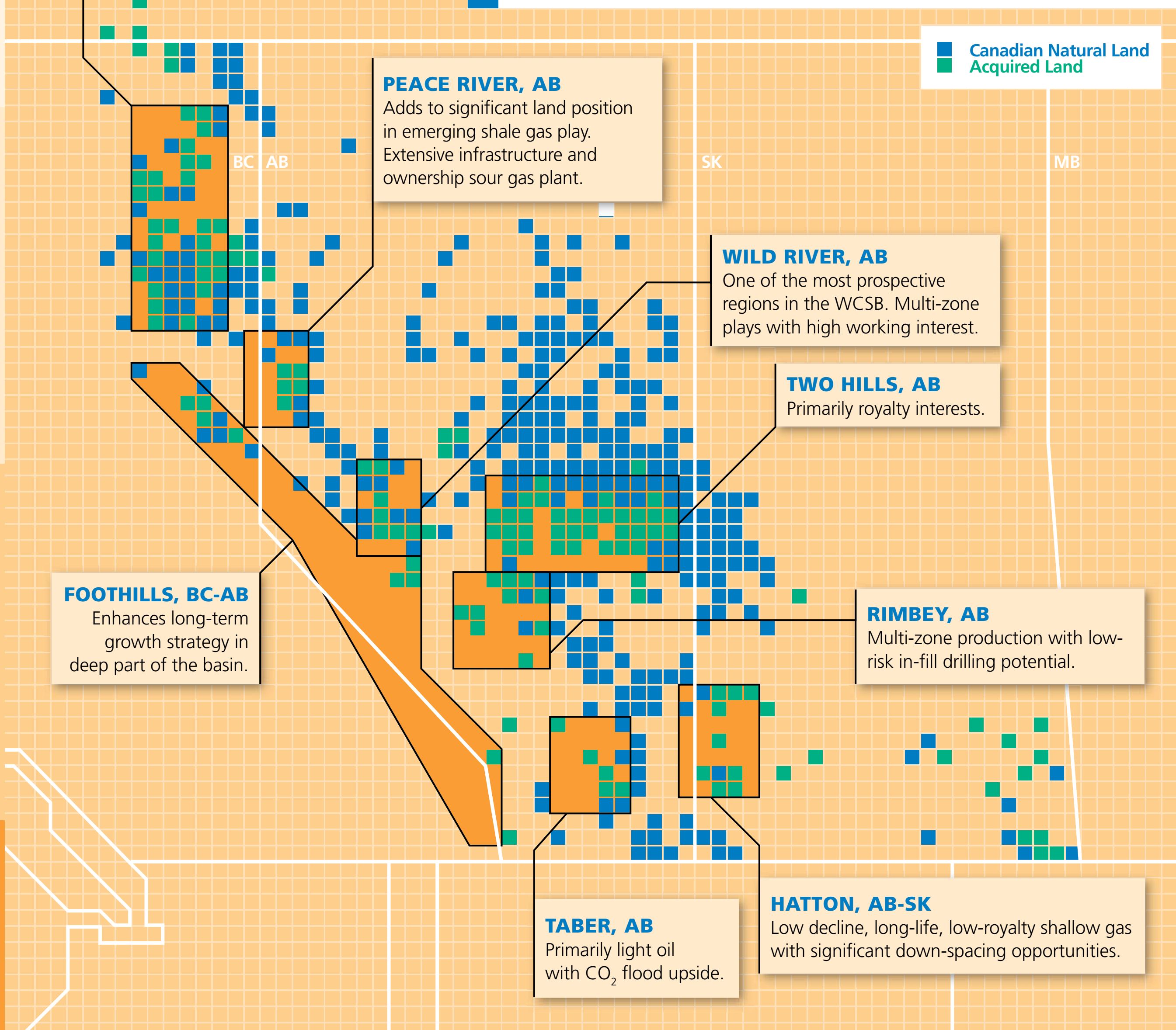
WHAT TO EXPECT IN 2007 AND BEYOND

The 2007 drilling program includes seven net natural gas wells on Canadian Natural's core properties at Murray, Copton and Cabin. Ongoing exploration effort and extensive new 3D seismic combined with the ACC assets have resulted in a high quality drilling inventory that will access significant resource potential on the Company's 366,000 acres of undeveloped lands. Drilling activity levels will grow to more than 10 wells per year after 2007 and we have an achievable plan to grow volumes by an average of 11% over the five year plan.

CASE STUDY

Acquisition of ACC Assets

The acquisition of ACC blended well with existing lands and infrastructure, providing significant upside to an already deep portfolio. The upside potential is significant – both in terms of optimization of existing operations but leveraging the expertise of both organizations. Adding 1.5 million acres of undeveloped land provides years of new drilling inventory. The addition of 2,800 miles of pipeline and access to seven major natural gas facilities greatly enhances value. The synergies of the two asset bases are expected to create value for shareholders for years to come.

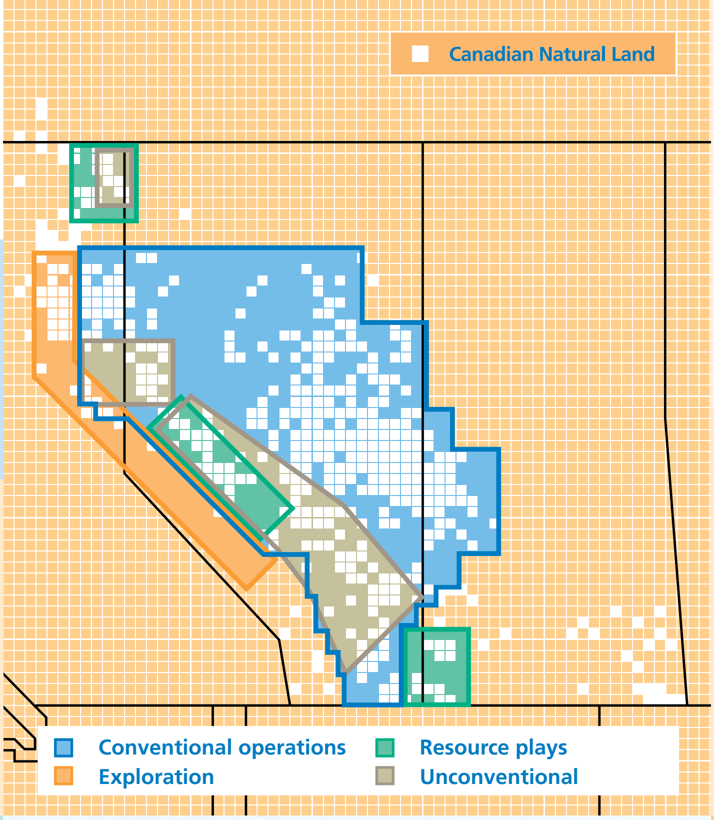


North American Natural Gas (continued)

CASE STUDY

Natural Gas Resource Potential

We believe that our natural gas portfolio contains resource potential well beyond the 5.9 tcf of Company gross proved and probable reserves currently recognized by our independent reserves engineers.



CONVENTIONAL OPERATIONS

These represent the traditional low-risk exploitation assets upon which we have built an extensive infrastructure. They extend across each of our core regions and generate excellent returns, albeit at a generally shorter reserve life.

EXPLORATION

These activities are characterized as high-risk/high-reward. An extreme example of this was the Ladyfern Slave Point field which went on record as one of the most prolific fields in WCSB history during 2001-2004. In addition to ongoing Slave Point exploration, we have greatly ramped our Foothills expertise over the past few years and have experienced positive results as a result.

RESOURCE PLAYS

These larger scale plays are generally of low to moderate risk and of a longer resource life. As techniques are optimized they become very repeatable and can offer excellent returns. Examples of these types of plays are the Helmet, shallow gas, Cardium and Horseshoe Canyon CBM.

UNCONVENTIONAL

Characterized as massive opportunities where technology and better geological understanding will unlock vast potential over time. Examples of this include Mannville CBM and various shale gas opportunities, including the Doig, Wilrich and Muskwa currently identified by us.

North American Crude Oil and NGLs

Canadian Natural is the largest producer of crude oil and NGLs in western Canada; our production is a blend of light and heavy crude oils augmented by NGLs which are produced in conjunction with natural gas. In 2006 average production volumes increased by 6%, reflecting another successful year of drilling and development programs. The depth of our asset base and the importance of our balanced product mix were revealed in mid 2006 when we refocused our drilling and development activity from natural gas to crude oil as a result of commodity prices. Our crude oil development strategy is based on low risk exploitation combined with our expertise in recovery techniques. This allows us to maximize crude oil recovery from both mature and new crude oil pools.

Light Crude Oil and NGLs

THE ASSET

We produce light crude oil and NGLs in all of the Company's western Canadian core regions. In North America, our light crude oil assets are largely developed however we continue to grow light crude oil production through a strategy of waterflood implementation and optimization, development drilling, new pool discoveries and acquisitions. The vast majority of the Company's light pools are produced under waterflood resulting in high recovery factors and low production decline rates. We are also evaluating and field testing the application of EOR technologies on several pools to further improve crude oil recovery.

2006 ACTIVITY

In 2006, Canadian Natural's light crude oil drilling and development programs pursued four initiatives:

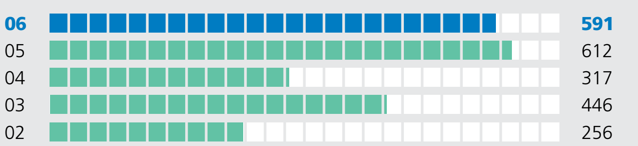
- Low risk, infill and step-out drilling in crude oil pools located in the Northern Plains, Northwest Alberta, Northeast British Columbia and the Southeast Saskatchewan core regions;
- Waterflood optimization programs in all our core regions. Our strong technical team, dedicated solely to waterflood optimization, continues to improve our waterflood performance through detailed reservoir characterization and analysis of production data;
- Continued pilot testing of polymer flooding to improve crude oil recovery in a mature waterflood; and
- Continuing pilot testing of a CO_2 flood on the Enchant pool in the Southern Plains.

WHAT TO EXPECT IN 2007 AND BEYOND

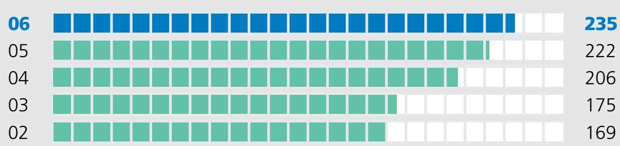
For 2007, Canadian Natural will continue to focus on waterflood and tertiary recovery opportunities. More than 100 net wells are planned for our 2007 light crude oil drilling program.

Canadian Natural will focus on waterflood enhancements to add incremental light crude oil reserves. We estimate that just a 1% improvement in recovery factor could yield an incremental 42 million barrels of reserves. In addition to the enhanced crude oil recovery initiatives our defined plan includes over 400 new well locations to be drilled over the next five years.

North American successful crude oil wells drilled (net wells)



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



North American Crude Oil and NGLs (continued)

Pelican Lake Crude Oil

THE ASSET

This massive, shallow crude oil pool in our Northern Plains core region is estimated to contain up to four billion barrels of OOIP and continues to provide excellent opportunities for production and reserves growth. The Pelican Lake pool now accounts for 8% of the Company's total proved reserves. We developed this pool exclusively with horizontal wells to minimize the environmental impact, reduce development costs and provide greater well productivity. We own and operate three centralized treating facilities in the area. Although priced similarly to heavy crude oil, our Pelican Lake crude oil production yields netbacks typical of medium crude oil due to our ability to maintain low operating costs.

2006 ACTIVITY

At Pelican Lake, 2006 proved to be very successful year:

- We continued to extend the developable area of the existing pool and drilled 73 net primary producing horizontal wells;
- 14 net stratigraphic wells were drilled to identify further pool extensions and other new pools in the area;
- We continued to expand the commercial waterflood project and have now converted 12% of our field to waterflood. A total of 28.5 sections are under waterflood with 87 net production wells and 82 net injection wells;
- The five well polymer flood pilot test that was initiated in 2005 has responded extremely well with production increasing from 50 bbl/d in May 2005 to over 600 bbl/d by December 2006. These results have lead to the commercial expansion of this EOR technology with 36 additional wells undergoing polymer flood by the end of 2006;
- Additional producing and undeveloped assets were acquired north of Pelican Lake that have promising growth potential.

Production in 2006 averaged 30,000 bbl/d, a 30% increase from 2005 levels, as a result of waterflood and polymer flood success and the continued drilling of primary wells. By the end of 2006 the Pelican Lake pool had approximately 100 million barrels from Canadian Natural lands.

WHAT TO EXPECT IN 2007 AND BEYOND

The 2007 program will see Canadian Natural drilling 64 net horizontal wells for primary production and five additional net stratigraphic wells to delineate pool extensions. The continued development of the Pelican Lake waterflood and polymer enhanced waterflood are the priority in 2007 and we plan to convert an additional 17.5 sections to polymer flood and 6.8 sections to waterflood. This will entail drilling 68 net horizontal infill production wells and converting 61 net producing wells into 39 polymer and 22 water injection wells. Recovery factors under primary production are approximately 5% of the OOIP and we are conservatively forecasting the recoveries could reach 17.5% through polymer flooding. The polymer flooding process is likely suitable for approximately half of the field which could yield significant incremental recovery at Pelican Lake.

Primary Heavy Crude Oil

THE ASSET

Canadian Natural's historic growth in primary heavy oil production has been achieved through drilling and through opportunistic acquisitions. Heavy oil is produced from repeatable, shallow, low risk, multi-zone wells. This leads to low finding and development costs, exceptional drilling success rates and many secondary zone recompletion opportunities. The region is also natural gas prone and development drilling can lead to both natural gas and heavy oil discoveries. With over 1.6 million acres of undeveloped land and 200,000 acres of developed land, we dominate production and operations within the Bonnyville/Lloydminster primary producing area of our Northern Plains core region. This dominance allows us to minimize capital by conducting large scale drilling and development programs. We also minimize and control our production costs through owning and operating central treating facilities, maximizing their utilization and using our size to achieve economies of scale. Ownership of the ECHO crude oil sales pipeline reduces our transportation costs and allows us to be the only producer capable of delivering undiluted heavy oil into our blending facilities at Hardisty, Alberta.

2006 ACTIVITY

During 2006 we drilled 292 heavy oil net wells and recompleted approximately 500 wells to secondary zones. In 2006 record netbacks were achieved for our heavy oil production as a result of high prices, our low operating costs and our low finding and development costs.

To further improve the recovery factors for crude oil we commenced planning for a 2007 EOR pilot project that will test the viability of a recovery process using hydrocarbon vapor.

WHAT TO EXPECT IN 2007 AND BEYOND

For 2007, 369 heavy oil locations are forecast to be drilled and a further 470 net wells will be recompleted. Our defined growth plan forecasts that over 1,550 net well locations will be drilled during the next five years, keeping production relatively flat. We will continue to pursue the development of applicable technologies to further improve crude oil recovery and are currently conducting research both in the field and in the laboratory. We estimate our developed primary heavy oil lands to contain 7 billion to 10 billion barrels of OOIP; a modest 1% increase in recovery would equate to over 70 million barrels of incremental recoverable crude oil.

Thermal (In-Situ) Heavy Crude Oil

THE ASSET

Canadian Natural is the second largest producer of thermal in-situ heavy crude oil in Canada and we also have has some of the best undeveloped thermal oil sands leases in Canada. Our thermal oil production is focused on the Primrose Cyclic Steam Stimulation ("CSS") project in the Cold Lake region and the Tangleflags thermal project in Saskatchewan. We also have further development potential at Cold Lake with the 40,000 bbl/d Primrose East expansion project that is currently under development. In all, we have more than 400,000 undeveloped acres of land suitable for thermal recovery processes. These assets provide the basis for the long-term growth of thermal oil production for the Company. Our technical expertise, our asset base and years of experience operating and constructing thermal projects has placed Canadian Natural as an industry leader in thermal in-situ oil recovery.

2006 ACTIVITY

In 2006 Canadian Natural's multi-year thermal development program took its first significant step with the first production from our Primrose North expansion project. As forecasted, production from the expansion project reached peak stabilized production production of 30,000 bbl/d in 2006, only 7 months after start-up in November, 2006. This project will be first of many as we are targeting to bring on a new thermal project every 2-3 years for the foreseeable future. As a result of the Primrose North expansion and the continued development and optimization at our Primrose South project our thermal crude oil production reached a record 64,000 bbl/d, or a 21% increase from 2005.

WHAT TO EXPECT IN 2007 AND BEYOND

In 2007, we plan to drill an additional 58 net horizontal wells at Primrose as part of the ongoing project. As part of our long-term thermal project expansion plans we will also drill more than 130 net stratigraphic wells to further define our leases at Primrose East, Kirby, Grouse, Birch Mountain and Gregoire Lake. Drilling and facility construction will start at our Primrose East expansion project where first production is targeted for 2009.

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. We continue to push the development of new technologies including geo-steering during drilling, infill drilling and steam additives to enhance recoveries.

North American Crude Oil and NGLs (continued)

CASE STUDY

Crude Oil Resource Potential

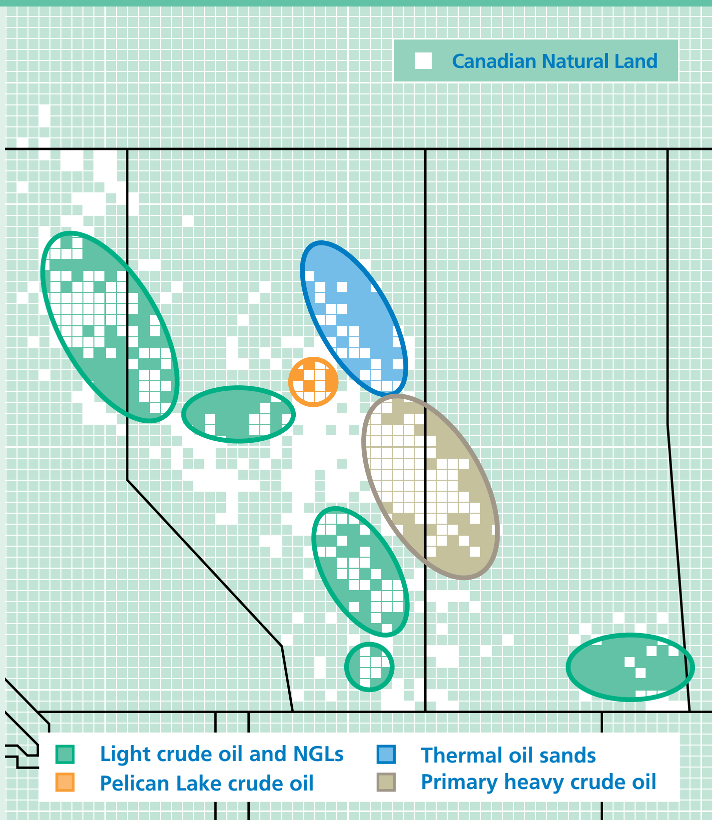
In North America we have a diverse crude oil portfolio with both light and heavy crude oil production. While optimizing our light crude oil production it is heavy crude oil that will continue to drive our crude oil growth. We have one of the largest heavy crude oil overall asset bases in the WCSB with an estimated 65 billion barrels of OOIP.

Our challenge is to find ways to economically recover as much of our resource as possible and develop the markets capable of absorbing this new crude oil. We have addressed this latter issue through our 3-phase marketing plan which has been articulated over the past three years. Our recovery plans include:

Realizing our probable reserves by optimizing those pools currently on production.

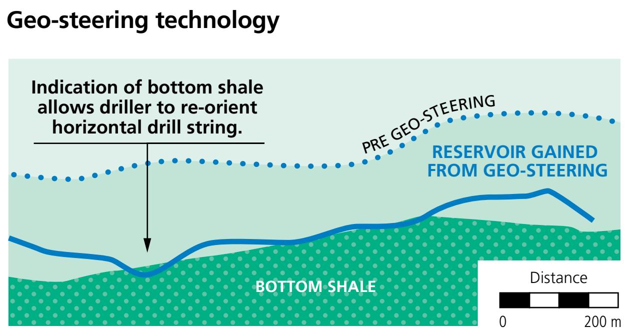
Executing "The Defined Plan" of oil development over the next 10 to 15 years, including additional thermal in-situ projects, polymer flooding at Pelican Lake and elsewhere and light crude oil EOR. These projects are currently in various stages of planning and evaluation.

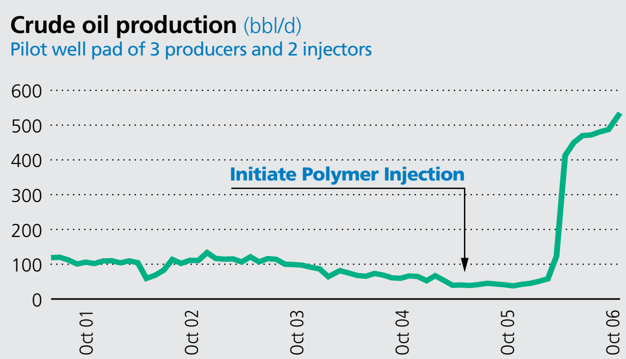
Delivering our Future Resource Potential comprising additional thermal in-situ and other EOR projects, which are in stages of field testing or are currently being researched.

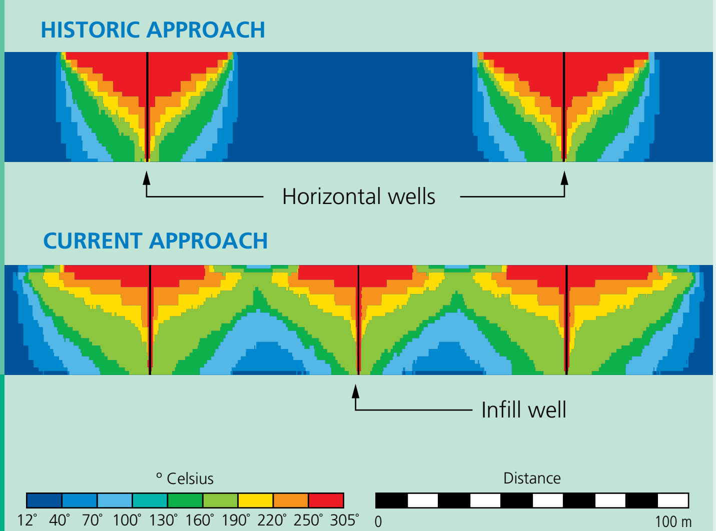


CASE STUDY

Technology Highlight







Geo-steering

When drilling horizontal wells, optimal wellbore placement is near the bottom of the reservoir. Past methods were inefficient, commonly involved drilling out the bottom of the reservoir into the underlying shales, then correcting the trajectory of the wellbore. Today, we have a adapted the technology of geo-steering used in conventional offshore to drilling oil sands wells. This methodology detects the presence of the reservoir base through logging while drilling and allows the wellbore trajectory to be adjusted to maintain the optimal distance from the base of the reservoir. This leads to savings in drilling time and could add millions of barrels of resource potential through optimal placement of the wellbore in even relatively thin reservoir.

Pelican Lake Polymer Flood

At Pelican Lake we have successfully implemented waterflooding in portions of the pool, largely against conventional wisdom which would not expect success in a thin, heavy crude oil reservoir. We now believe that waterflooding could improve recovery factors from the base level of 3-5% OOIP up to 10-15% OOIP. To further enhance the waterflooding process we began evaluation and field testing polymer flood and have achieved great early success at a reasonable cost. We estimate recovery factors could ultimately increase to 15-25% OOIP in the better portions of the reservoir. Ultimately this EOR technology could add over 250 million barrels of resource potential.

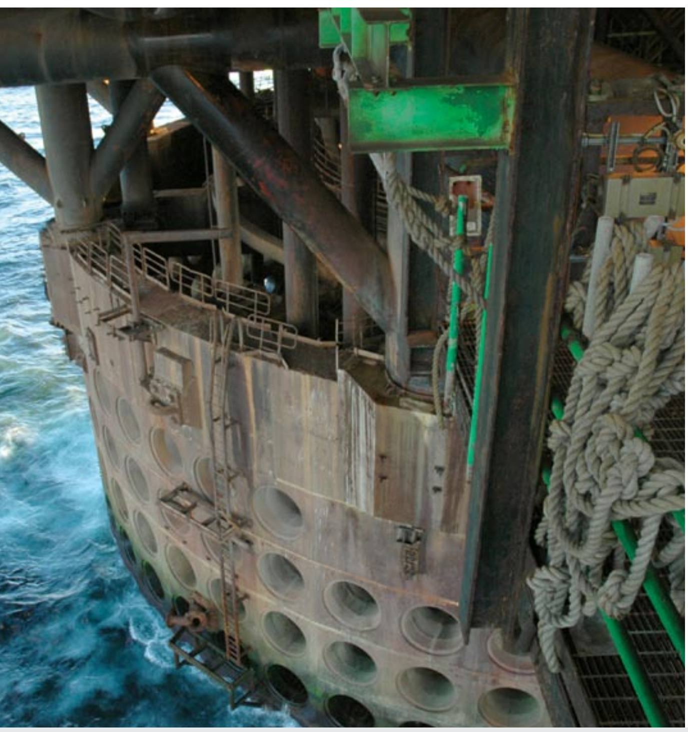
Primrose In-Situ Infill Program

Canadian Natural historically believed that cyclic steaming of horizontal wells spaced at 120 meters was sufficient to "heat" and recover oil in the intervening reservoir. We've now proven through extensive engineering studies and infill well drilling that the optimal spacing is approximately 60 meters. We believe that this could improve recovery factors at Primrose from approximately 25% to more than 40% OOIP adding 300 million barrels of resource potential. At this interwell spacing there is also additional potential to convert to a gravity drainage process and increase recovery even further.

International

ALLEN M. KNIGHT,
SENIOR VICE-PRESIDENT, INTERNATIONAL & CORPORATE DEVELOPMENT

Our international operations provide a vehicle for continued light crude oil production growth. A disciplined and focused approach is essential to successful value creation in the international arena, therefore, we limit our exposure to those basins where we see the greatest opportunities and we can best lever our business strategies. We capitalize on our core competency of mature basin exploitation in the North Sea where the business parallels that of the WCSB in many ways. Offshore West Africa provides development opportunities and significant exploration upside, capitalizes on strong government relationships developed over the past years and leverages the technical/operational expertise in the North Sea. In both basins, we operate in areas where we dominate the land base and have the infrastructure to support our operations.



United Kingdom Portion of the North Sea

THE ASSET

Achievements in the basin are a result of the successful utilization of our mature basin exploitation expertise. The first stage is predicated upon optimizing existing facilities and waterfloods. This includes infill drilling, recompletions, and workover wells and optimizing waterfloods to increase production, lower costs and extend field life. The second stage incorporates more near-pool development and exploration in order to maximize utilization of common facilities and ultimately extend all fields' economic lives. In 2006 and beyond, increasing emphasis on this type of work will be made.

2006 ACTIVITY

During 2006, 7.4 net crude oil wells were drilled along with 1.8 injection wells, effectively offsetting production declines.

In the Northern North Sea, production at Ninian reached its highest level since Canadian Natural became operator of the Field in 2002. Work progressed on the Columba Terrace and Lyell Field developments with subsea infrastructure being installed at both locations and drilling operations commencing.

In the Central North Sea, following the consolidation of production from the Banff/Kyle Hub to a single FPSO, operating costs were reduced and the economic life of both fields extended. At Banff, work was completed to upgrade gas compression capacity, resulting in an immediate uplift in crude oil production from the field. At the T-Block Hub, high impact subsea wells were delivered, resulting in the highest production levels for three years being achieved.

International successful crude oil wells drilled (net wells)

06	**12**
05	15
04	11
03	12
02	8

International total production (mboe/d)

06	**101**
05	95
04	86
03	76
02	50

WHAT TO EXPECT IN 2007 AND BEYOND

During 2007, 7 net crude oil wells are expected to be drilled, allowing average daily production to be maintained at 2006 levels. At the Murchison Hub, a major turnaround will be carried out to upgrade aging facilities in order to optimize plant efficiency and uptime. At the Ninian Hub, a major turnaround at Ninian Southern, driven by planned integrity maintenance schedules, will be completed. Major development projects at Kyle, Lyell and the Columba Terraces will move into execution phase, both on the drilling and construction side. At the B-Block Hub, gas compression capacity upgrade work will be carried out and third party oil will be received at the Balmoral facility, resulting in a significant reduction in field operating costs.

Offshore West Africa

THE ASSET

Canadian Natural has two exploration blocks comprising approximately 55,000 net developed and undeveloped acres of land located offshore Côte d'Ivoire. Currently three producing properties, East Espoir, West Espoir and Baobab, are operated.

2006 ACTIVITY

In Côte d'Ivoire in 2006 4.1 net crude oil wells and 1.7 service and injection wells were drilled. Also during the year, first oil at our West Espoir field was delivered on schedule during the third quarter During 2006, problems were encountered with control of sand and solids production, leading to 5 of the 10 production wells at Baobab being shut in by the end of the year. The Company plans to recomplete these wells, but only at such time as a deepwater rig can be secured on commercially acceptable terms.

In October 2005, we completed the acquisition of the permit to develop the Olowi Field, offshore Gabon. The permit comprises a 90% interest in the production sharing agreement for the Block containing the Olowi Field, located 20 kilometers offshore and in 30 meters of water. Olowi has been delineated by the drilling of 15 wells by the previous owner and potentially contains as much as 215 million barrels of 34˚ API light crude OOIP. The crude oil reservoir is overlain by a large gas cap with potentially up to 589 billion cubic feet of Original Gas In Place ("OGIP"). A development plan, comprising an FPSO and four drilling towers was filed with the Gabonese Government in late 2005, and approved in February 2006. The development of the crude oil reserves commenced in late 2006, with first production targeted for late 2008, with a peak rate of 20,000 bbl/d net expected in 2009.

WHAT TO EXPECT IN 2007 AND BEYOND

During 2007, a further 3 net crude oil wells will be drilled at West Espoir, with each well being brought online as it is completed. At East Espoir, a rigless coiled tubing intervention program will be carried out to further optimize production, and at Baobab we will remain focused on securing a deepwater rig to allow the tremendous potential at Baobab to be delivered, but only on commercially acceptable terms. In Gabon, the Olowi development project will be progressed towards first oil in late 2008, with construction of the drilling towers being carried out in 2007 and drilling operations commencing in 2008.

Canadian Natural plans to leverage its reputation and experience in the region to capture additional exploration and exploitation opportunities within this core region.

Horizon Oil Sands Project

RÉAL J.H. DOUCET,
SENIOR VICE-PRESIDENT,
OIL SANDS

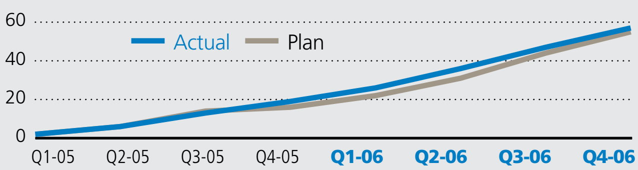
We hold extensive leases in the Athabasca region north of Fort McMurray that are estimated to contain approximately 16 billion barrels of original bitumen in place. The Horizon Oil Sands Project represents a phased development accessing 6 billion barrels of mineable bitumen resource potential, depending upon sales price assumptions. The Horizon Project includes a surface oil sands mining and bitumen extraction plant coupled with on-site bitumen upgrading and associated infrastructure to produce synthetic crude oil. Due to the massive resource base, the mine and plant facilities are expected to produce for decades to come without the production declines normally associated with crude oil production. Today we are well into Phase 1 construction with first oil targeted for the second half of 2008 ramping to 110,000 bbl/d by the end of that year. Subsequent phases are planned with total ultimate potential production from the leases of approximately 500,000 bbl/d by 2017. At 34° API gravity, low sulphur and fully sweet, the project is designed to produce a high quality SCO product reducing marketing risks.

The technology at the Horizon Project is based on that currently in use at existing plants, effectively mitigating technology risk in Phase 1. That being said, our plant has been configured in a manner 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 greenhouse gas emission levels.

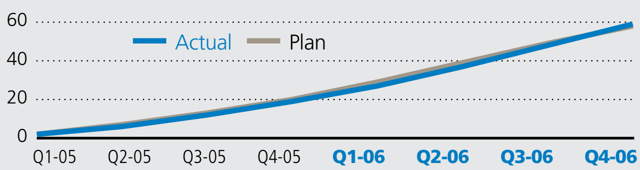
The geological risk associated with the project is very low. On this lease, over 16 stratigraphic net wells per section have been drilled to identify overburden levels, and test the ore composition and quality. The result is a well designed mine plan that has been optimized to support the bitumen extraction and processing. To ensure efficient construction, we have implemented an "80/100 rule", requiring about 80% of engineering to be complete and 100% of materials purchased prior to construction of major packages. This has resulted in minimal rework and very little standby time. In addition our execution and labour strategy combined with the fly-in/fly-out ability of workers and our first-class camp facilities has positioned the Horizon Project as "the employer of choice" in the region.

Finally, 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.

Percentage of work progress (cumulative)



Percentage of capital spending (cumulative)



2006 ACTIVITY

Significant progress was achieved during 2006 with overall Phase 1 project progress entering the year at 19% and exiting at 57%, slightly ahead of our plan.

Overall detailed engineering reached 94% completion and was substantially completed in most areas. Similarly, procurement exited at 84% complete with most major equipment purchased and on site. A total of over $5.1 billion in purchase orders and contracts were awarded through the end of 2006.

Use of modular construction in remote yards located at larger metropolitan areas was a strategic decision made early in the project execution plan. While this greatly reduces requirements for on-site labour it is only successful if logistics and transportation efforts are successful. Our program has proven to be successful having delivered 973 oversized loads, or 59% of Phase 1 requirements, through the end of 2006.

The construction effort itself has reached 42% complete by year end, as efforts changed from one of largely civil and underground work in 2005 and early 2006 to above ground construction and equipment installation. By the end of the year the following accomplishments were achieved:

- Set 333 main piperack modules, essentially forming the core infrastructure of the plant.
- Delayed cokers were significantly advanced following completion of foundations, delivery and erection of four coke drums and setting of topside drill towers.
- Numerous reactors were completed and transported to site with subsequent placement in early 2007.
- Constructed 7 of 14 Inclined Plate Separators units for bitumen froth cleaning.
- Ore Preparation Area completed construction of the Mechanically Stabilized Earth Shear Wall and transported the 800 tonne module assemblies onto their foundations.
- Mine overburden removal has moved 25 million bank cubic meters, which is approximately 35% complete and 4% ahead of target.
- 5 of 6 Modular Substations have been installed with High Voltage cable terminations ongoing.
- Completed and commissioned for use, two additional on-site worker camps, increasing on-site accommodation capacity to 5,000.
- Completed numerous ancillary buildings and commissioned various support systems/services, including fire and emergency response.

Horizon Oil Sands Project (continued)

Creative Approach Continues to Create Value for Shareholders

Inflationary pressures have been significant throughout the industry for the past few years and are the result of higher steel/commodity prices and increased demands for contractor expertise and labour/services. Our team has been able to mitigate the majority of these pressures. Further, we remain on track for final commissioning during the third quarter of 2008.

Some of the elements of this successful execution included:

- An upfront emphasis on design and execution strategy. This facilitated a better definition of both what we were going to build and how we were going to build it. This greater level of project definition facilitated the award of approximately 68% of Phase 1 costs through lump sum arrangements.
- A flexible contracting strategy, with Canadian Natural as the general contractor. This afforded us the ability to alter work packages to fit the current market. Additionally, in the case of the Tar River Diversion project, self perform the work to drive appropriate pricing and, in effect, build and train our operations team and core supervision.
- Our labour strategy of 'managed open site' combined with fly-in / fly-out. Through this we have accessed the labour force across Canada, bringing workers in from coast to coast. We currently have up to 55 flights per week into our site from all across Canada and continue to assess new locations and available labour forces. Workforce numbers at site have met the Project labour demand with 4,000 trades persons working on site in December.

In 2007 we anticipate mechanical completion in several plants within the project and will continue to recruit and build the operating and maintenance teams for the new facilities. We have had operations staff involved in the design, procurement and construction of the Horizon Project and their input and direction has been invaluable as we ensure the facilities will operate efficiently and be easily maintained.

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 pinch points and ensure that we have adequate contingencies in place during start-up. Currently we have 134 operations people on staff developing start up procedures, preparing training programs, recruiting additional staff, establishing maintenance programs, and already operating several plant systems.

Our Operations team has the opportunity to test run many of its programs through the early operation of many plant systems. Currently operating some of its mine equipment, and operating several plant facilities such the water treatment system, sewage treatment plant, natural gas distribution, power distribution, and communications systems the team has already developed several early learnings that are incorporated into later facility start up plans.

The 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. With respect to future expansions, we have started consolidating results from the Phase 2 Engineering Design Specification and have identified a number of potential options for Phases 2/3 execution within the current high cost environment. We will fully evaluate these options and provide further updates as we move through that process.

Year-End Reserves

INDEPENDENT EVALUATION

- For the year ended December 31, 2006, 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 probable crude oil, natural gas liquids ("NGL") and natural gas reserves* and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional 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 two principal differences between the two standards. The first is the additional 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 Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using yearend constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of this Annual Report. The Company has elected to provide the net present value(7) of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information.

- For the year ended December 31, 2006, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Oil Sands Project and prepare an Evaluation Report on the Company's 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 probable crude oil, NGL and natural gas reserves.

- The Reserve 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, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

NORTH AMERICA CONVENTIONAL NET RESERVES

- Natural gas proved reserves increased by 35%, replacing 323% of 2006 production. Similarly, crude oil and NGLs proved reserves increased by 28%, replacing 357% of production. This was accomplished at all-in finding and on-stream cost of $15.86 per barrels of oil equivalent for proved reserves and $9.53 per barrels of oil equivalent for proved and probable reserves.

INTERNATIONAL CONVENTIONAL NET RESERVES

- North Sea proved reserves grew by 10 million barrels of oil equivalent to 305 million barrels of oil equivalent or about 16% of total proved Company reserves. Reserve additions were primarily achieved through optimization of waterflood design, an infill drilling program and recompletions.

- In Offshore West Africa, where the Government share of production is contractually determined as a percentage of production volume and apportioned between income tax and royalties for reserves and accounting purposes based on the terms of the Production Sharing Contracts ("PSC"), proved reserves decreased to 139 million barrels of oil equivalent as a result of a 2006 corporate income tax rate reduction that effectively increased the allocation to royalty. Generally, the Company receives a greater portion of production until capital development costs are recouped whereupon government allocation of production substantially increases. With the current high world crude oil price, these projects generally require fewer of the reserves to cover payout of capital costs, thereby reducing the reserves ultimately allocated to the Company over the field life.

CONVENTIONAL PROVED UNDEVELOPED NET RESERVES ("PUDS")

- In the Evaluation Reports, 47% of crude oil proved reserves were assigned to the proved undeveloped category. This is a 9 percentage point increase from the 38% recorded in 2005. Of the 2006 crude oil PUD reserves, 57% are associated with our thermal oil sands projects where extensive pool delineation and geological analysis justifies continued development and expansion.

- 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.

CONVENTIONAL PROVED AND PROBABLE NET RESERVES

- In the Evaluation Reports, total proved and probable reserves increased by 30%, driven largely by the 42% increase in North America.

OIL SANDS MINING RESERVES

- The Horizon Project's gross lease proved bitumen reserves as of December 31, 2006 under constant prices were 2.3 billion barrels. The gross lease proved and probable bitumen reserves were 3.5 billion 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

NET RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS (1)(2)

	December 31, 2006			
	Proved Developed (3)	**Proved Undeveloped (3)**	**Proved Total (3)**	**Proved and Probable (4)**
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 (%) (5)			**295%**	**472%**
Cost to develop ($/boe) (6)				
10% discount	**1.33**	**6.46**	**3.32**	**3.08**
15% discount	**1.12**	**5.80**	**2.94**	**2.66**
Present value of conventional reserves ($ millions) (7)				
10% discount	**20,028**	**7,469**	**27,497**	**37,291**
15% discount	**17,296**	**5,247**	**22,543**	**29,350**

NET RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS (1)(2)

	December 31, 2005			
	Proved Developed (3)	Proved Undeveloped (3)	Proved Total (3)	Proved and Probable (4)
Crude oil and NGLs (mmbbl)				
North America	402	292	694	1,035
North Sea	214	76	290	417
Offshore West Africa	80	54	134	206
	696	422	1,118	1,658
Natural gas (bcf)				
North America	2,300	441	2,741	3,548
North Sea	16	13	29	69
Offshore West Africa	10	62	72	110
	2,326	516	2,842	3,727
Total reserves (mmboe)	1,083	509	1,592	2,279
Reserve replacement ratio (%) (5)			145%	195%
Cost to develop ($/boe) (6)				
10% discount	0.79	5.69	2.36	2.55
15% discount	0.67	5.15	2.11	2.25
Present value of conventional reserves ($ millions) (7)				
10% discount	24,275	6,342	30,617	38,682
15% discount	20,939	4,881	25,820	31,642

OIL SANDS MINING RESERVES [1][8]

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

	As at Dec 31, 2006		As at Dec 31, 2005	
	Proved Total	**Proved and Probable**	Proved Total	Proved and Probable
Gross lease reserves, before royalties (mmbbl)				
Bitumen	**2,275**	**3,530**	2,235	3,430
Synthetic crude oil *	**1,866**	**2,962**	1,833	2,878
Net reserves, after royalties (mmbbl)				
Bitumen	**1,853**	**2,872**	1,848	2,848
Synthetic crude oil *	**1,596**	**2,542**	1,626	2,566

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

NET CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION [1][2]

	North America	**North Sea**	**Offshore West Africa**	**Total**
Proved reserves (mmbbl)				
Reserves, December 31, 2004	648	303	115	1,066
Extensions and discoveries	98	–	–	98
Infill drilling	3	3	2	8
Improved recovery	–	–	–	–
Property purchases	–	–	15	15
Property disposals	(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**
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**
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2004	926	415	196	1,537
Extensions and discoveries	200	–	–	200
Infill drilling	3	5	6	14
Improved recovery	–	–	–	–
Property purchases	–	–	17	17
Property disposals	(4)	–	–	(4)
Production	(70)	(25)	(8)	(103)
Revisions of prior estimates	(20)	22	(5)	(3)
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**

NET CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION [(1)(2)]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2004	2,591	27	72	2,690
Extensions and discoveries	506	–	–	506
Infill drilling	22	–	–	22
Improved recovery	8	–	–	8
Property purchases	6	–	–	6
Property disposals	(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**
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**
Proved and probable reserves (bcf)				
Reserves, December 31, 2004	3,319	57	90	3,466
Extensions and discoveries	645	–	–	645
Infill drilling	23	–	1	24
Improved recovery	14	–	–	14
Property purchases	8	–	–	8
Property disposals	(30)	–	–	(30)
Production	(411)	(7)	(1)	(419)
Revisions of prior estimates	(20)	19	20	19
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**

NET CONVENTIONAL FINDING AND ONSTREAM COSTS [(1)(2)]

	2006	2005	2004	Three Year Total
Net reserve replacement expenditures ($ millions)	**8,727**	3,361	4,259	**16,347**
Net reserve additions (mmboe) [(9)]				
Proved	**540**	251	354	**1,145**
Proved and probable	**865**	337	453	**1,655**
Finding and on stream costs ($/boe) [(10)]				
Proved	**16.16**	13.41	12.03	**14.28**
Proved and probable	**10.09**	9.97	9.40	**9.88**

NET RESERVES CLASSIFICATION BY PRODUCT (1)(2)

	December 31, 2006			
Reserves Net of Royalties	**Proved Developed** (3)	**Proved Undeveloped** (3)	**Proved Total** (3)	**Proved and Probable** (4)
Light crude oil and NGLs				
North America	6%	1%	7%	6%
North Sea	11%	4%	15%	14%
Offshore West Africa	3%	3%	6%	7%
Total	20%	8%	28%	27%
Heavy crude oil				
North America - Primary Heavy	5%	1%	6%	4%
North America - Pelican Lake	3%	5%	8%	7%
North America - Thermal	7%	18%	25%	34%
Total	15%	24%	39%	45%
Total crude oil and NGLs				
North America	21%	25%	46%	51%
North Sea	11%	4%	15%	14%
Offshore West Africa	3%	4%	7%	7%
Total	35%	33%	68%	72%
Natural gas				
North America	25%	7%	32%	27%
North Sea	–	–	–	–
Offshore West Africa	–	–	–	1%
Total	25%	7%	32%	28%
Total boe	**60%**	**40%**	**100%**	**100%**

(1) Reserve estimates and net 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)
2006	51.11	61.05	41.94	58.93
2005	46.12	61.04	32.64	58.21
2004	32.14	44.04	17.45	40.47

Natural gas	Company Average Price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	Alberta AECO C (C$/mmbtu)	British Columbia Huntingdon Sumas (C$/mmbtu)
2006	6.07	5.52	6.13	6.52
2005	9.45	10.08	9.99	9.53
2004	6.44	6.62	6.78	6.94

A foreign exchange rate of US$0.86/C$1.00 was used in the 2006 and the 2005 evaluations; US$0.83/C$1.00 was used in the 2004 evaluation.

(2) Net reserves mean the Company's working interest share of gross reserves after consideration of royalties.

(3) Proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission ("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.

(4) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("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.

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

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

(7) Net present values of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment costs have been applied against future net revenues.

(8) 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.

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

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

Management's Discussion & Analysis

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, 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; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists or 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 availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the ability of the Company to attract the necessary labour required to build its 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; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent, 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 "Risks and Uncertainties" on page 64.

Disclosure related to future commodity pricing, production volumes, royalties, capital expenditures and other 2007 guidance provided throughout this Management's Discussion and Analysis, including the information provided in the "Outlook" section on pages 69 and 70, constitutes forward looking statements as described above.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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 were 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 the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis ("MD&A") 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, 2006. 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 16 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2005. 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 well head. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise. The following discussion and analysis refers primarily to the Company's 2006 financial results compared to 2005 and 2004, unless otherwise indicated. In addition, this discussion details the Company's capital program and outlook for 2007.

Certain figures related to the presentation of gross revenues and gross transportation and blending expense provided for prior years have been reclassified to conform to the presentation adopted in 2006.

Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2006 and its Annual Information Form for the year ended December 31, 2006, is available on SEDAR at www.sedar.com.

This MD&A is dated March 15, 2007.

ABBREVIATIONS

ACC	Anadarko Canada Corporation
AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	American Petroleum Institute
ARO	Asset retirement obligations
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
FPSO	Floating Production, Storage and Offtake Vessel
GAAP	Generally accepted accounting principles
GJ	gigajoule
Heavy Differential	Heavy crude oil differential from WTI
Horizon Project	Horizon Oil Sands Project
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	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 objective is 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 acquisition of new reserves. The Company strives to meet this objective 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 wealth. 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 of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of conventional crude oil and natural gas reserves and undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14-17° API oil, but receives medium quality crude netbacks due to low production costs and low 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 or new additions; and
- Supporting and participating in projects that will increase the conversion capacity for heavy crude oil.

Operational discipline and cost control are central to the Company. By controlling costs consistently 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 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 construction period of the Horizon Project.

Strategic accretive acquisitions like the acquisition of ACC 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. These targeted acquisitions should provide additional free cash flow during the construction years of the Horizon Project while still achieving targeted returns.

Highlights for the year ended December 31, 2006 are as follows:

- Achieved record levels of net earnings;
- Achieved record crude oil and NGLs and natural gas production;
- Achieved its revised annual production guidance for crude oil and NGLs and natural gas;
- Completed the acquisition of ACC for net cash consideration of $4,641 million;
- Completed 57% of Phase 1 construction of the Horizon Project;
- Completed all major 2006 milestones on the Horizon Project before winter's onset;

- Achieved full recovery of the Company's capital investments in the Primrose North and South Fields;
- Received Gabonese Government approval of its development plan for the Olowi PSC offshore Gabon and received Board of Directors sanction for development in November 2006;
- Delivered first oil from West Espoir and completed a successful infill drilling campaign at East Espoir in the Company's Offshore West Africa geographic segment; and
- Purchased 485,000 common shares for a cost of $28 million under the Company's Normal Course Issuer Bid.

NET EARNING AND CASH FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		2006		2005		2004
Revenue, before royalties [(1)]	$	**11,643**	$	11,130	$	8,269
Net earnings	$	**2,524**	$	1,050	$	1,405
Per common share						
– basic	$	**4.70**	$	1.96	$	2.62
– diluted	$	**4.70**	$	1.95	$	2.60
Adjusted net earnings from operations [(2)]	$	**1,664**	$	2,034	$	1,405
Per common share						
– basic	$	**3.10**	$	3.79	$	2.62
– diluted	$	**3.10**	$	3.78	$	2.60
Cash flow from operations [(3)]	$	**4,932**	$	5,021	$	3,769
Per common share						
– basic	$	**9.18**	$	9.36	$	7.03
– diluted	$	**9.18**	$	9.33	$	6.98
Dividends declared per common share	$	**0.30**	$	0.236	$	0.200
Total assets	$	**33,160**	$	21,852	$	18,372
Total long-term liabilities	$	**19,399**	$	9,790	$	9,196
Capital expenditures, net of dispositions	$	**12,025**	$	4,932	$	4,633

(1) Blending costs previously netted against gross revenues in prior years have been reclassified to transportation and blending expense to conform to the presentation adopted in 2006.
(2) Adjusted net earnings from operations is a non-GAAP term 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 following reconciliation 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.

($ millions)		2006		2005		2004
Net earnings as reported	$	**2,524**	$	1,050	$	1,405
Stock-based compensation, net of tax (a)		**95**		481		168
Unrealized risk management (gain) loss, net of tax (b)		**(674)**		607		(27)
Unrealized foreign exchange loss (gain), net of tax (c)		**114**		(85)		(75)
Effect of statutory tax rate changes on future income tax liabilities (d)		**(395)**		(19)		(66)
Adjusted net earnings from operations	$	**1,664**	$	2,034	$	1,405

(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, net of taxes, flow through net earnings, or are capitalized to the Horizon Project.
(b) Derivative financial instruments not designated as hedges are recorded at fair value on the balance sheet, with changes in fair value, net of taxes, 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 and are immediately recognized in net earnings.
(d) All substantively enacted adjustments in applicable income tax rates 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 changes during 2006 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 Offshore West Africa. Jurisdictional income tax rate changes in North America in 2005 resulted in a reduction of future income tax liabilities of $19 million (2004 - $66 million reduction).

(3) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. 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. Cash flow from operations may not be comparable to similar measures presented by other companies.

($ millions)	2006	2005	2004
Net earnings	$ 2,524	$ 1,050	$ 1,405
Non-cash items:			
Depletion, depreciation and amortization	2,391	2,013	1,769
Asset retirement obligation accretion	68	69	51
Stock-based compensation	139	723	249
Unrealized risk management activities	(1,013)	925	(40)
Unrealized foreign exchange loss (gain)	134	(103)	(94)
Deferred petroleum revenue tax expense (recovery)	37	(9)	(45)
Future income tax	652	353	474
Cash flow from operations	$ 4,932	$ 5,021	$ 3,769

In 2006, the Company reported record net earnings of $2,524 million compared to net earnings of $1,050 million in 2005 (2004 – $1,405 million). Net earnings for the year ended December 31, 2006 included unrealized after-tax income of $860 million related to the effects of risk management activities, statutory tax rate changes on future income tax liabilities, fluctuations in foreign exchange rates and stock-based compensation expense (2005 – unrealized after-tax expenses of $984 million; 2004 – $nil). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2006 decreased to $1,664 million from $2,034 million in 2005 (2004 – $1,405 million) primarily due to decreased natural gas pricing, increased realized risk management losses, increased production expense and increased depletion, depreciation and amortization expense, and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger benchmark crude oil pricing and increased crude oil and NGLs and natural gas sales volumes.

Operating results in 2006 were impacted by the acquisition of ACC completed in November 2006. The Company completed the acquisition 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 is located in Western Canada and consists of natural gas weighted assets. The operating results of ACC have been consolidated with the results of the Company effective November 2006. Total production from the ACC properties averaged approximately 67,600 boe/d for the two months of November and December, while natural gas production from the ACC properties averaged approximately 354 mmcf/d.

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 expenditure program 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 expected 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 expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

As effective as the Company's hedges are against reference commodity prices, a portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management asset reflects, at December 31, 2006, the implied price differentials for the non-designated hedges for future periods. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

Due to the changes in crude oil and natural gas forward pricing, and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities for the year ended December 31, 2006 (2005 - $925 million unrealized loss, $607 million after-tax; 2004 - $40 million unrealized gain, $27 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.

The Company also recorded a $139 million ($95 million after-tax) stock-based compensation expense for the year ended December 31, 2006 in connection with the 8% increase in the Company's share price for the year ended December 31, 2006 (Company's share price as at: December 31, 2006 – C$62.15; December 31, 2005 – C$57.63; December 31, 2004 – C$25.63; December 31, 2003 – C$16.34). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options, 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 balance sheet 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 earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. 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, 2006 decreased slightly to $4,932 million ($9.18 per common share) from $5,021 million ($9.36 per common share) in 2005 (2004 – $3,769 million or $7.03 per common share). The decrease was primarily due to decreased natural gas pricing, increased realized risk management losses, increased production expense and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger benchmark crude oil pricing and increased sales volumes.

In 2006, the Company's average sales price per bbl of crude oil and NGLs increased to $53.65 per bbl from $46.86 per bbl in 2005 (2004 – $37.99 per bbl). The Company's average natural gas price decreased to $6.72 per mcf from $8.57 per mcf in 2005 (2004 – $6.50 per mcf).

Total production of crude oil and NGLs before royalties increased to a record 331,998 bbl/d from 313,168 bbl/d in 2005 (2004 – 282,489 bbl/d). The increase in crude oil and NGLs production primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, the acquisition of ACC, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced August 2005.

Total natural gas production before royalties increased to 1,492 mmcf/d from 1,439 mmcf/d in 2005 (2004 – 1,388 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 decrease due to the effects of the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures.

Total crude oil and NGLs and natural gas production volumes before royalties increased to 580,724 boe/d from 552,960 boe/d in 2005 (2004 – 513,835 boe/d).

Operating highlights	**2006**	2005	2004
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 53.65**	$ 46.86	$ 37.99
Royalties	**4.48**	3.97	3.16
Production expense	**12.29**	11.17	10.05
Netback	**$ 36.88**	$ 31.72	$ 24.78
Natural gas ($/mcf) (1)			
Sales price (2)	**$ 6.72**	$ 8.57	$ 6.50
Royalties	**1.29**	1.75	1.35
Production expense	**0.82**	0.73	0.67
Netback	**$ 4.61**	$ 6.09	$ 4.48
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	**$ 47.92**	$ 48.77	$ 38.45
Royalties	**5.89**	6.82	5.37
Production expense	**9.14**	8.21	7.35
Netback	**$ 32.89**	$ 33.74	$ 25.73

(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 most recently completed quarters:

($ millions, except per common share amounts)

2006	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties [1]	$ 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	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11
– diluted	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11

2005	Total	Dec 31	Sep 30	Jun 30	Mar 31 [2]
Revenue, before royalties [1]	$ 11,130	$ 3,319	$ 3,163	$ 2,420	$ 2,228
Net earnings (loss)	$ 1,050	$ 1,104	$ 151	$ 219	$ (424)
Net earnings (loss) per common share					
– basic	$ 1.96	$ 2.06	$ 0.28	$ 0.41	$ (0.79)
– diluted	$ 1.95	$ 2.06	$ 0.28	$ 0.41	$ (0.79)

(1) Blending costs previously netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in the fourth quarter of 2006.
(2) Restated to reflect two-for-one share split in May 2005.

The Company's quarterly consolidated revenues increased 27% to $2,826 million in the fourth quarter of 2006 from $2,228 million in the first quarter of 2005. Quarterly revenues during 2006 primarily reflected increased world benchmark crude oil prices and increased crude oil and NGLs and natural gas sales volumes, partially offset by decreased natural gas prices. Quarterly revenues during 2005 primarily reflected increased world benchmark crude oil and natural gas prices and increased crude oil and NGLs and natural gas sales volumes.

- Crude oil prices reflected demand growth and continuing geopolitical uncertainties. Hurricane activity in the Gulf of Mexico in the third quarter of 2005 further contributed to increased world benchmark crude oil pricing. As a result, the Company's realized crude oil and NGLs price increased from C$39.81 per bbl for the first quarter of 2005 to C$47.27 per bbl for the fourth quarter of 2006. Realized natural gas prices decreased in 2006 from 2005 primarily due to decreased heating demand during the winter months and decreased cooling demand during the summer months. The Company's realized natural gas price decreased slightly from C$6.68 per mcf for the first quarter of 2005 to C$6.66 per mcf for the fourth quarter of 2006

- A stronger Canadian dollar reduced the Canadian dollar sales price the Company received for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks. The US / Canadian dollar average exchange rate increased from 0.8152 for the first quarter of 2005 to 0.8781 for the fourth quarter of 2006.

- Crude oil and NGLs and natural gas sales volumes increased in 2006 over 2005. The increase in crude oil and NGLs production from 2005 primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes from the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced August 2005. The increase in natural gas production from 2005 primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by production decreases due to the effects of the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures. In total, daily production increased from 530,316 boe/d day in the first quarter of 2005 to 613,764 boe/d for the fourth quarter of 2006.

In addition to commodity prices and sales volumes, quarterly net earnings were impacted by:

- Increased production expense primarily due to the ACC acquisition and industry-wide inflationary cost pressures.

- Increased depletion, depreciation and amortization expense primarily due to increased finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the acquisition of ACC and increased estimated future costs to develop the Company's proved undeveloped reserves.

- Unrealized expense (recovery) due to the mark-to-market treatment of the Company's stock-based compensation liability.

- Unrealized gains and losses from the mark-to-market treatment of the Company's commodity price hedges not designated as hedges for accounting purposes.

- Unrealized foreign exchange gains and losses due to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling.

- Jurisdictional corporate tax rate changes substantively enacted in the period.

BUSINESS ENVIRONMENT

(Yearly average)		2006		2005		2004
WTI benchmark price (US$/bbl) [1]	$	66.25	$	56.61	$	41.43
Dated Brent benchmark price (US$/bbl)	$	65.18	$	54.45	$	38.28
Differential to LLB blend (US$/bbl)	$	21.69	$	20.83	$	13.44
Differential to LLB blend as a % of WTI		33%		37%		32%
Condensate benchmark price (US$/bbl)	$	66.24	$	57.25	$	41.62
NYMEX benchmark price (US$/mmbtu)	$	7.26	$	8.56	$	6.09
AECO benchmark price (C$/GJ)	$	6.62	$	8.05	$	6.43
US/Canadian dollar average exchange rate (US$)	$	0.8818	$	0.8253	$	0.7683

(1) Refers to West Texas Intermediate crude oil prices per barrel at Cushing, Oklahoma.

COMMODITY PRICES

World benchmark crude oil prices increased during the first part of 2006 due to ongoing demand growth and geopolitical uncertainties. However, pricing significantly declined later in the year, reflecting higher crude oil inventories. In December 2006, WTI averaged US$62.09 per bbl, a decline of 21% from the record high of US$78.40 per bbl reached in July 2006. WTI averaged US$66.25 per bbl in 2006, an increase of 17% compared to US$56.61 per bbl in 2005 (2004 – US$41.43 per bbl).

The Company's realized crude oil price increased from 2005 as a result of the increased WTI price and the narrower Heavy Differential. Heavy Differentials averaged 33% for 2006 compared to 37% for 2005 (2004 – 32%). The narrowing of the Heavy Differentials from 2005 was primarily due to reduced availability of imported grades from Venezuela and Mexico, reduced Canadian production of heavy crude oil and the removal of logistical constraints in accessing new markets in the US Gulf Coast due to the Pegasus and Spearhead pipelines commencing operations during 2006. The increase in realized crude oil prices from 2005 was partially offset by the negative impact of a strengthening Canadian dollar relative to the US dollar. A strengthening Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.

The Company anticipates continued volatility in the crude oil markets as inventory levels remain high and given the unpredictable nature of geopolitical events.

Brent averaged US$65.18 per bbl in 2006, an increase of 20% compared to US$54.45 per bbl in 2005 (2004 – US$38.28 per bbl). Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which has benefited from strong European and Asian demand in 2006.

NYMEX natural gas prices averaged US$7.26 per mmbtu in 2006, a decrease of 15% from US$8.56 per mmbtu in 2005 (2004 – US$6.09 per mmbtu). AECO natural gas pricing in 2006 decreased 18% from 2005 to average C$6.62 per GJ. The decrease in natural gas pricing in 2006 from 2005 reflected the impact of exceptionally mild winter weather and reduced heating demand, relatively stable summer weather and reduced cooling demand, and the continuing impact of high natural gas inventory levels.

The Company anticipates a challenging natural gas pricing environment in the near term given the high storage levels. Longer term natural gas pricing will continue to be largely weather dependent.

OPERATING AND CAPITAL COSTS

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has lead to inflationary production and capital cost pressures throughout the North American crude oil and natural gas industry, particularly related to natural gas drilling activity and oil sands developments. The strong commodity price environment has also impacted costs in international basins. Specifically, the high demand for offshore drilling rigs continues and securing rigs on commercially acceptable terms is an ongoing challenge.

The oil and gas industry is also experiencing cost pressures related to increasingly stringent environmental regulations, both in North America and internationally. In addition, environmental regulations in Canada intended to reduce greenhouse gas emissions are pending and the impact of the legislation is uncertain at this time.

These increased cost pressures and environmental regulations may adversely impact the Company's future net earnings, cash flow and increase the costs of capital projects.

REVENUE, BEFORE ROYALTIES

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES

		Changes due to				Changes due to			
($ millions)	2004	Volumes	Prices	Other	2005	**Volumes**	**Prices**	**Other**	**2006**
North America									
Crude oil and NGLs [1]	$ 3,300	$ 170	$ 847	$ –	$ 4,317	**$ 198**	**$ 747**	**$ –**	**$ 5,262**
Natural gas	3,401	208	1,029	–	4,638	**168**	**(1,002)**	**–**	**3,804**
	6,701	378	1,876	–	8,955	**366**	**(255)**	**–**	**9,066**
North Sea									
Crude oil and NGLs	1,223	31	382	–	1,636	**(168)**	**132**	**–**	**1,600**
Natural gas	94	(59)	(12)	–	23	**(4)**	**(3)**	**–**	**16**
	1,317	(28)	370	–	1,659	**(172)**	**129**	**–**	**1,616**
Offshore West Africa									
Crude oil and NGLs	208	182	86	–	476	**344**	**111**	**–**	**931**
Natural gas	14	(6)	1	–	9	**12**	**(2)**	**–**	**19**
	222	176	87	–	485	**356**	**109**	**–**	**950**
Subtotal									
Crude oil and NGLs	4,731	383	1,315	–	6,429	**374**	**990**	**–**	**7,793**
Natural gas	3,509	143	1,018	–	4,670	**176**	**(1,007)**	**–**	**3,839**
	8,240	526	2,333	–	11,099	**550**	**(17)**	**–**	**11,632**
Midstream	68	–	–	9	77	**–**	**–**	**(5)**	**72**
Intersegment eliminations and other [2]	(39)	–	–	(7)	(46)	**–**	**–**	**(15)**	**(61)**
Total	$ 8,269	$ 526	$ 2,333	$ 2	$ 11,130	**$ 550**	**$ (17)**	**$ (20)**	**$ 11,643**

(1) Blending costs previously netted against gross revenues in prior years have been reclassified to transportation and blending expense to conform to the presentation adopted in 2006.
(2) Eliminates primarily internal transportation and electricity charges.

Revenue increased 5% to $11,643 million in 2006 from $11,130 million in 2005 (2004 – $8,269 million). The increase was primarily due to increased crude oil and NGLs and natural gas sales volumes in North America and Offshore West Africa and increased realized crude oil and NGLs prices, partially offset by decreased realized natural gas prices.

In 2006, 22% of the Company's crude oil and natural gas revenue was generated outside of North America (2005 – 19%; 2004 – 19%). North Sea accounted for 14% of crude oil and natural gas revenue in 2006 (2005 – 15%; 2004 – 16%), and Offshore West Africa accounted for 8% of crude oil and natural gas revenue in 2006 (2005 – 4%; 2004 – 3%).

ANALYSIS OF PRODUCT PRICES [1]

	2006	2005	2004
Crude oil and NGLs ($/bbl) [2]			
North America	**$ 46.52**	$ 39.62	$ 33.16
North Sea	**$ 72.62**	$ 66.57	$ 51.37
Offshore West Africa	**$ 67.99**	$ 59.91	$ 49.05
Company average	**$ 53.65**	$ 46.86	$ 37.99
Natural gas ($/mcf) [2]			
North America	**$ 6.77**	$ 8.65	$ 6.61
North Sea	**$ 2.66**	$ 3.17	$ 3.73
Offshore West Africa	**$ 5.37**	$ 5.91	$ 5.25
Company average	**$ 6.72**	$ 8.57	$ 6.50
Company average ($/boe) [2]	**$ 47.92**	$ 48.77	$ 38.45
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**64%**	54%	54%
Natural gas	**36%**	46%	46%

(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.

Realized crude oil and NGLs prices increased 14% to average $53.65 per bbl in 2006 from $46.86 per bbl in 2005 (2004 – $37.99 per bbl). The increase from 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar.

The Company's realized natural gas price decreased 22% to average $6.72 per mcf in 2006 from $8.57 per mcf in 2005 (2004 – $6.50 per mcf), reflecting record levels of natural gas inventory in North America, primarily due to the impact of exceptionally mild winter weather in 2006 that reduced heating demand and relatively stable summer weather that reduced cooling demand.

NORTH AMERICA

North America realized crude oil prices increased 17% to average $46.52 per bbl in 2006 from $39.62 per bbl in 2005 (2004 – $33.16 per bbl). The increase from 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a 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 2006, the Company contributed approximately 136,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian West Coast and the US Gulf Coast where crude oil cargos can be sold on a world-wide basis. With a view to expanding markets for its heavy crude oil, the Company has committed to 25,000 bbl/d of capacity on the Pegasus Pipeline, which carries crude oil to the Gulf of Mexico. The Pegasus Pipeline is made up of a series of segments extending from Patoka, Illinois to Nederland, Texas, near the Gulf Coast. The Company's first sales from the Pegasus Pipeline occurred in April 2006. The Company also entered into an agreement to supply 25,000 bbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of five years, with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

North America realized natural gas prices decreased 22% to average $6.77 per mcf in 2006 from $8.65 per mcf in 2005 (2004 – $6.61 per mcf), primarily due to reduced seasonal heating demand and reduced summer cooling demand in 2006.

A comparison of the price received for the Company's North America production by product type is as follows:

	2006	2005	2004
Wellhead price (1) (2)			
Light crude oil and NGLs (C$/bbl)	**$ 63.09**	$ 58.41	$ 45.90
Pelican Lake crude oil (C$/bbl)	**$ 45.02**	$ 38.39	$ 32.12
Primary heavy crude oil (C$/bbl)	**$ 41.35**	$ 33.53	$ 28.99
Thermal heavy crude oil (C$/bbl)	**$ 40.98**	$ 32.29	$ 29.00
Natural gas (C$/mcf)	**$ 6.77**	$ 8.65	$ 6.61

(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 9% to average $72.62 per bbl in 2006 from $66.57 per bbl 2005 (2004 – $51.37 per bbl). The increase in the realized crude oil price from 2005 was due primarily to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar in 2006 compared to 2005.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 13% to average $67.99 per bbl in 2006 from $59.91 per bbl in 2005 (2004 – $49.05 per bbl). The increase in the realized crude oil price from 2005 was due primarily to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar in 2006 compared to 2005.

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

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

In 2006, approximately 478,000 barrels of crude oil produced in the Company's North America and international operations were added to inventory and excluded from results of operations, decreasing cash flow from operations for the year by approximately $7 million.

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2006	2005	2004
Crude oil and NGLs (bbl/d)			
North America	**235,253**	221,669	206,225
North Sea	**60,056**	68,593	64,706
Offshore West Africa	**36,689**	22,906	11,558
	331,998	313,168	282,489
Natural gas (mmcf/d)			
North America	**1,468**	1,416	1,330
North Sea	**15**	19	50
Offshore West Africa	**9**	4	8
	1,492	1,439	1,388
Total barrels of oil equivalent (boe/d)	**580,724**	552,960	513,835
Product mix			
Light crude oil and NGLs	**26%**	26%	24%
Pelican Lake crude oil	**5%**	4%	4%
Primary heavy crude oil	**16%**	17%	19%
Thermal heavy crude oil	**11%**	10%	8%
Natural gas	**42%**	43%	45%

DAILY PRODUCTION, NET OF ROYALTIES

	2006	2005	2004
Crude oil and NGLs (bbl/d)			
North America	**205,382**	191,751	180,011
North Sea	**59,940**	68,487	64,598
Offshore West Africa	**35,212**	22,293	11,221
	300,534	282,531	255,830
Natural gas (mmcf/d)			
North America	**1,185**	1,125	1,048
North Sea	**15**	18	50
Offshore West Africa	**9**	4	7
	1,209	1,147	1,105
Total barrels of oil equivalent (boe/d)	**502,024**	473,742	440,022

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 increased 6% to 331,998 bbl/d from 313,168 bbl/d in 2005 (2004 – 282,489 bbl/d). The increase in crude oil and NGLs production from 2005 reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes from the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced August 2005. Crude oil and NGLs production for 2006 was in line with the Company's revised guidance of 325,000 to 336,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Total natural gas production before royalties increased 4% to 1,492 mmcf/d from 1,439 mmcf/d in 2005 (2004 – 1,388 mmcf/d). The increase in natural gas production from 2005 primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by production decreases due to the impact of the Company's decision to reduce natural gas drilling activity in 2006, made in response to inflationary costs in Western Canada. Natural gas production for 2006 was at the bottom end of the Company's revised guidance of 1,492 to 1,501 mmcf/d.

In 2007, annual production is forecasted to average between 315,000 and 360,000 bbl/d of crude oil and NGLs and between 1,594 and 1,664 mmcf/d of natural gas.

NORTH AMERICA

North America crude oil and NGLs production in 2006 increased 6% to average 235,253 bbl/d from 221,669 bbl/d in 2005 (2004 – 206,225 bbl/d). The increase in production from 2005 was primarily due to increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project and the ACC acquisition.

North America natural gas production in 2006 increased 4% to average 1,468 mmcf/d from 1,416 mmcf/d in 2005 (2004 – 1,330 mmcf/d). The increase in natural gas production from 2005 reflected the ACC acquisition, partially offset by production declines due to the Company's decision to reduce natural gas drilling activity. The ACC acquisition was completed in November with results included from that date. To date, the ACC properties are performing as expected.

NORTH SEA

North Sea crude oil production in 2006 was 60,056 bbl/d, a decrease of 12% from 68,593 bbl/d in 2005 (2004 – 64,706 bbl/d). Production levels in 2006 were in line with expectations, reflecting the production effects of planned maintenance shutdowns in the second half of 2006.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production in 2006 increased 60% to 36,689 bbl/d from 22,906 bbl/d in 2005 (2004 – 11,558 bbl/d). The increase from 2005 was primarily due to the impact of a full year's production from the Baobab Field, first crude oil from West Espoir and a successful infill drilling campaign at East Espoir. The increase was partially offset by continuing challenges with sand and solids production at the Baobab Field that resulted in the shut in of 5 production wells. The Company does not plan to recomplete these wells until such time as a deepwater rig can be secured on commercially acceptable terms.

ROYALTIES

		2006		2005		2004
Crude oil and NGLs ($/bbl) (1)						
North America	$	**5.86**	$	5.37	$	4.21
North Sea	$	**0.13**	$	0.10	$	0.08
Offshore West Africa	$	**2.81**	$	1.62	$	1.43
Company average	$	**4.48**	$	3.97	$	3.16
Natural gas ($/mcf) (1)						
North America	$	**1.31**	$	1.78	$	1.40
North Sea	$	**–**	$	–	$	–
Offshore West Africa	$	**0.22**	$	0.16	$	0.15
Company average	$	**1.29**	$	1.75	$	1.35
Company average ($/boe) (1)	$	**5.89**	$	6.82	$	5.37
Percentage of revenue (2)						
Crude oil and NGLs		**8%**		8%		8%
Natural gas		**19%**		20%		21%
Boe		**12%**		14%		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 falls under the oil sands royalty regime and is calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). 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.

Crude oil and NGLs royalties increased in 2006 primarily due to increased crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the second half of the year. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of net profit. North America crude oil and NGLs royalties per bbl are anticipated to be 14% to 16% of gross revenue in 2007, an increase from 13% in 2006 (2005 – 14%; 2004 – 13%).

Natural gas royalties per mcf decreased from 2005 primarily due to decreased benchmark natural gas prices. Benchmark natural gas prices decreased primarily in response to reduced demand and increased storage levels. North America natural gas royalties per mcf are anticipated to be 21% to 23% of gross revenue in 2007, an increase from 19% in 2006 (2005 – 21%; 2004 – 21%).

NORTH SEA

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining North Sea royalty represents 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 revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue 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 revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Field are expected to be fully recovered early in 2007, increasing royalty rates and current income taxes in accordance with the PSCs. The Company's capital investments in the Baobab Field are now not expected to be fully recovered until approximately 2012 due to the ongoing production curtailments resulting from limitations to sand screen effectiveness.

In connection with corporate income tax rate reductions enacted by the Government of Côte d'Ivoire during the year that were effective January 1, 2006, royalty rates as a percentage of gross revenue increased from approximately 3% in 2005 to approximately 4% in 2006. As a result, production volumes net of royalties decreased approximately 2% in 2006 from 2005, in accordance with the terms of the PSC's. Royalty rates in 2007 are anticipated to be 13% to 15% of gross revenue due to the Company's expected full recovery of its capital investments in the Espoir Field.

PRODUCTION EXPENSE

	2006	2005	2004
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 11.73**	$ 10.49	$ 8.94
North Sea	**$ 17.57**	$ 14.94	$ 14.03
Offshore West Africa	**$ 7.45**	$ 6.50	$ 7.59
Company average	**$ 12.29**	$ 11.17	$ 10.05
Natural gas ($/mcf) (1)			
North America	**$ 0.81**	$ 0.71	$ 0.62
North Sea	**$ 1.40**	$ 2.44	$ 2.07
Offshore West Africa	**$ 1.19**	$ 1.05	$ 1.33
Company average	**$ 0.82**	$ 0.73	$ 0.67
Company average ($/boe) (1)	**$ 9.14**	$ 8.21	$ 7.35

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

NORTH AMERICA

North America crude oil and NGLs production expense in 2006 increased 12% to $11.73 per bbl from $10.49 per bbl in 2005 (2004 - $8.94 per bbl). The increase in production expense from 2005 was primarily due to increased industry wide service costs and increased cyclic steaming costs related to the Company's thermal crude oil projects, due to the timing of secondary steaming cycles.

North America natural gas production expense in 2006 increased 14% to $0.81 per mcf from $0.71 per mcf in 2005 (2004 - $0.62 per mcf), due to increased cost pressures.

Production expense per boe in 2007 is anticipated to continue to reflect industry wide inflationary cost pressures.

NORTH SEA

North Sea crude oil production expense increased on a per barrel basis from 2005 due to planned maintenance shutdowns, varying sales volumes on a relatively fixed cost base and the timing of liftings from various fields.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expense on a per barrel basis increased from 2005 primarily due to continuing operating challenges with sand and solids resulting in decreased production volumes at Baobab, on a relatively fixed operating cost base.

MIDSTREAM

($ millions)	**2006**	2005	2004
Revenue	**$ 72**	$ 77	$ 68
Production expense	**23**	24	20
Midstream cash flow	**49**	53	48
Depreciation	**8**	8	7
Segment earnings before taxes	**$ 41**	$ 45	$ 41

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION [1]

($ millions, except per boe amounts) [2]	2006	2005	2004
North America	$ 1,897	$ 1,595	$ 1,444
North Sea	297	306	265
Offshore West Africa	189	104	53
Expense	$ 2,383	$ 2,005	$ 1,762
$/boe	$ 11.27	$ 10.02	$ 9.37

(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 in 2006 increased 19% to $2,383 million from $2,005 million in 2005 (2004 – $1,762 million). The increase in DD&A expense in total and on a boe basis in 2006 from 2005 was primarily as a result of increased production combined with overall increases in finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the acquisition of ACC, and increased estimated future costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) [1]	2006	2005	2004
North America	$ 35	$ 34	$ 28
North Sea	31	34	22
Offshore West Africa	2	1	1
Expense	$ 68	$ 69	$ 51
$/boe	$ 0.32	$ 0.34	$ 0.27

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

Accretion expense is the increase in the carrying amount of the ARO due to the passage of time. ARO accretion expense was comparable to 2005.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) [1]	2006	2005	2004
Net expense	$ 180	$ 151	$ 125
$/boe	$ 0.85	$ 0.75	$ 0.66

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

Net administration expense in 2006 increased in total and on a boe basis from 2005 primarily due to increased insurance premiums, increased staffing and administrative costs, costs associated with the integration of ACC, and overall inflationary cost pressures.

STOCK-BASED COMPENSATION

($ millions)	2006	2005	2004
Stock-based compensation expense	$ 139	$ 723	$ 249

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 $139 million ($95 million after-tax) stock-based compensation expense during 2006 in connection with the 8% appreciation in the Company's share price (December 31, 2006 – C$62.15; December 31, 2005 – C$57.63; December 31, 2004 – C$25.63; December 31, 2003 – C$16.34). 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 quarterly 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 (2006 – $79 million; 2005 – $101 million; 2004 – $21 million). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2006, the Company paid $264 million for stock options surrendered for cash settlement (December 31, 2005 – $227 million; 2004 – $80 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) [1]		2006		2005		2004
Interest expense, gross	$	336	$	221	$	189
Less: capitalized interest, Horizon Project		196		72		–
Interest expense, net	$	140	$	149	$	189
$/boe	$	0.66	$	0.74	$	1.01
Average effective interest rate		5.7%		5.6%		5.2%

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

Gross interest expense increased from 2005 primarily due to increased debt levels associated with the ACC acquisition and the financing of Horizon Project capital expenditures. The increase was partially offset by the impact of the strengthening Canadian dollar, which decreased interest expense on the Company's US dollar denominated debt securities.

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. Changes in fair value of derivative financial instruments formally designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not formally designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all derivative financial instruments 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 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. Realized gains or losses on these contracts are included in risk management activities. Unrealized gains or losses on commodity price contracts not formally documented as hedges are also included in risk management activities.

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. Gains or losses on interest rate swap contracts formally designated as hedges are included in interest expense. Gains or losses on non-designated interest rate swap contracts are included in risk management activities.

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. Gains or losses on the foreign exchange component of all cross-currency swap contracts are included in risk management activities. Gains or losses on the interest component of cross-currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transactions are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Gains or losses on the termination of derivative financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

($ millions)		2006		2005		2004
Realized loss (gain)						
Crude oil and NGLs financial instruments	$	1,395	$	753	$	501
Natural gas financial instruments		(70)		283		5
Interest rate swaps		–		(9)		(32)
	$	1,325	$	1,027	$	474
Unrealized (gain) loss						
Crude oil and NGLs financial instruments	$	(736)	$	847	$	(47)
Natural gas financial instruments		(260)		77		–
Interest rate and currency swaps		(17)		1		7
	$	(1,013)	$	925	$	(40)
Total	$	312	$	1,952	$	434

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

		2006		2005		2004
Crude oil and NGLs ($/bbl) (1)	$	11.57	$	6.68	$	4.85
Natural gas ($/mcf) (1)	$	(0.13)	$	0.54	$	0.01

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

The realized gain on non-designated interest rate swaps would have decreased the Company's reported interest expense as follows:

($ millions, except interest rates)		2006		2005		2004
Interest expense as reported	$	140	$	149	$	189
Less: realized risk management gain		–		(9)		(32)
	$	140	$	140	$	157
Average effective interest rate		5.7%		5.2%		4.4%

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management asset reflected at December 31 2006, the implied price differentials for the non-designated hedges for future years. Due to changes in crude oil and natural gas forward pricing and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities in 2006 (2005 – a $925 million unrealized loss, $607 million after-tax; 2004 – a $40 million unrealized gain, $27 million after-tax).

The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

In addition to the net risk management asset recognized on the balance sheet 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).

Details relating to outstanding derivative financial instruments at December 31, 2006 are disclosed in note 12 to the Company's audited annual consolidated financial statements as at December 31, 2006.

Effective January 1, 2007, the Company will adopt new accounting standards relating to the accounting for and disclosure of financial instruments. Accordingly, the Company will record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the consolidated financial statements. The estimated effects on the Company's consolidated balance sheet are discussed in further detail on page 68 of this MD&A.

FOREIGN EXCHANGE

($ millions)		2006		2005		2004
Realized foreign exchange (gain) loss	$	(12)	$	(29)	$	3
Unrealized foreign exchange loss (gain)		134		(103)		(94)
Total	$	122	$	(132)	$	(91)

The Company's operating results are affected by 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 will result in increased revenue from the sale of the Company's production. Production expenses are subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar related to North Sea operations. 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 realized foreign exchange loss in 2006 was primarily the result of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange gain in 2006 was primarily related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The Canadian dollar ended the year at US$0.8581 compared to US$0.8577 at December 31, 2005 (December 31, 2004 – US$0.8308).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in Shareholders' Equity in the consolidated balance sheets.

TAXES

($ millions, except income tax rates)	**2006**	2005	2004
Taxes other than income tax			
Current	**$ 219**	$ 203	$ 210
Deferred	**37**	(9)	(45)
Total	**$ 256**	$ 194	$ 165
Current income tax			
North America	**$ 143**	$ 99	$ 101
North Sea	**30**	155	2
Offshore West Africa	**49**	32	13
Total	**$ 222**	$ 286	$ 116
Future income tax	**$ 652**	$ 353	$ 474
Effective income tax rate	**25.7%** (1)	37.8% (2)	29.6% (3)

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

(2) Includes the effect of a $19 million recovery due to a British Columbia corporate tax rate reduction enacted in 2005.
(3) Includes the effect of a $66 million recovery due to an Alberta corporate tax rate reduction enacted in 2004.

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian provincial capital taxes and surcharges. 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 and amount of capital expenditures incurred in Canada in any particular year.

Income tax rate changes during 2006 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, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2004, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $66 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduces 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 is being phased out and a deduction for actual crown royalties paid is being phased in. As a result in 2007, crown royalties will be fully deductible and the Company will no longer be eligible for resource allowance in 2007 and future years.

The following table shows the effect of non-recurring benefits on income taxes:

($ millions, except income tax rates)	**2006**	2005	2004
Income tax as reported			
Current income tax	**$ 222**	$ 286	$ 116
Future income tax expense	**652**	353	474
	874	639	590
Provincial corporate tax rate reductions	**161**	19	66
Canadian Federal and foreign corporate tax rate reductions	**234**	–	–
Total	**$ 1,269**	$ 658	$ 656
Expected effective income tax rate before non-recurring benefits	**37.3%**	39.0%	32.9%

The effective income tax rate for 2006 decreased slightly from 2005 due to the effects of the phased elimination of the resource allowance, the phased deductibility of crown royalties and foreign jurisdictional corporate tax rate changes substantively enacted during the year. In 2007, based on budgeted prices and the current availability of tax pools, the Company expects to be cash taxable in Canada in the amount of $45 million to $75 million.

NET CAPITAL EXPENDITURES [(1)]

($ millions)	2006	2005	2004
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions) [(2)]	**$ 4,733**	$ (320)	$ 1,835
Land acquisition and retention	**210**	254	120
Seismic evaluations	**130**	132	89
Well drilling, completion and equipping	**2,340**	2,000	1,394
Pipeline and production facilities	**1,314**	1,295	821
Total net reserve replacement expenditures	**8,727**	3,361	4,259
Horizon Project			
Phase 1 construction costs [(3)]	**2,768**	1,249	–
Phases 2 and 3 costs	**79**	–	–
Capitalized interest, stock-based compensation and other [(3)]	**338**	250	291
Total Horizon Project	**3,185**	1,499	291
Midstream	**12**	4	16
Abandonments [(4)]	**75**	46	32
Head office	**26**	22	35
Total net capital expenditures	**$ 12,025**	$ 4,932	$ 4,633
By segment			
North America	**$ 7,936**	$ 2,530	$ 3,355
North Sea	**646**	387	608
Offshore West Africa	**134**	439	295
Other	**11**	5	1
Horizon Project	**3,185**	1,499	291
Midstream	**12**	4	16
Abandonments [(4)]	**75**	46	32
Head office	**26**	22	35
Total	**$ 12,025**	$ 4,932	$ 4,633

(1) Net capital expenditures do not include non-cash property, plant and equipment additions or disposals.
(2) Includes Business Combinations.
(3) Certain prior period amounts have been reclassified with respect to stock-based compensation costs.
(4) Abandonments represent expenditures to settle AROs 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, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures in 2006 were $12,025 million compared to $4,932 million in 2005 (2004 – $4,633 million). The increase primarily reflected the $4,641[(1)] million acquisition of ACC (including working capital and other adjustments) and continued progress on the Company's larger, future growth projects, most notably the Horizon Project. Excluding the ACC acquisition and the Horizon Project, net capital expenditures were $4,085 million in 2006 compared to $3,433 million in 2005, reflecting the impact of $320 million in net property dispositions in 2005, and overall industry-wide inflationary pressures in 2006. During 2006, the Company drilled a total of 1,738 net wells consisting of 641 natural gas wells, 603 crude oil wells, 375 stratigraphic test and service wells, and 119 wells that were dry. The 375 stratigraphic test and service wells include 163 stratigraphic test wells related to the Horizon Project. This compared to 1,882 net wells drilled in 2005 (2004 – 1,449 net wells). The Company achieved an overall success rate of 91% in 2006, excluding the stratigraphic test and service wells (2005 - 93% and 2004 -91%).

(1) The preliminary allocation of the ACC purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

Property, plant and equipment	$ 6,249
Less – future income taxes	(1,438)
– asset retirement costs	(56)
Consideration for crude oil and natural gas properties	4,755
Non-cash working capital deficit assumed and other	(105)
Long-term debt assumed	(9)
Net purchase price - cash consideration	$ 4,641

NORTH AMERICA

North America, including the Horizon Project and the ACC acquisition, accounted for approximately 94% of the total capital expenditures for the year ended December 31, 2006 compared to approximately 83% in 2005 (2004 – 80%).

During 2006, the Company targeted 732 net natural gas wells, including 181 wells in Northeast British Columbia, 262 wells in the Northern Plains region, 177 wells in Northwest Alberta, and 112 wells in the Southern Plains region. The Company also targeted 619 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 292 heavy crude oil wells, 144 Pelican Lake crude oil wells, and 8 light crude oil wells were drilled. Another 114 wells targeting light crude oil were drilled outside the Northern Plains as well as 61 thermal crude oil wells in the Company's In-Situ Oil Sands area.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has taken the opportunity to access its large crude oil drilling inventory to maximize value in both the short and long term. To optimize netbacks in the short term, the Company will continue to focus on drilling crude oil wells in 2007 and, accordingly, will reduce natural gas drilling activity to manage overall capital spending. Deferred natural gas wells will be retained in the Company's prospect inventory, and will be drilled as natural gas commodity prices improve. Drilling on ACC acquired lands will be optimized as part of the overall capital program.

As part of the development of the Company's In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. At the end of 2006, the Company had drilled 186 stratigraphic test and observation wells and 61 thermal oil wells. With first steaming for the Primrose North expansion commencing November 2005, overall Primrose thermal production in 2006 increased to approximately 64,000 bbl/d from 53,000 bbl/d in 2005. Initial steaming of the projects was completed late in 2006.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands assets. The next phase of this development is 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. This phase of the expansion is anticipated to add an additional 40,000 bbl/d and received Board of Director's sanction in 2006. Detailed engineering and procurement is currently underway. The Company anticipates receiving regulatory approval for Primrose East in the first half of 2007, with drilling and construction planned to begin in the second half of 2007, and production expected to commence in 2009.

The next phase of the Company's In-Situ Oil Sands assets expansion is the Kirby project located 120 km north of the existing Primrose facilities. The Kirby project is anticipated to add an additional 30,000 bbl/d of production growth. The Company is targeting to file its formal regulatory application documents for this project in the second half of 2007. First steaming is anticipated to begin in 2011.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through 2006. Drilling consisted of 144 horizontal wells, with plans to drill 132 additional horizontal wells in 2007. The response from the polymer flood pilot continues to be positive. Based on the results of the pilot, the Company commenced the installation of 12 additional polymer skids in 2006 as part of the approval of the commercial polymer flood project. Pelican Lake production averaged approximately 30,000 bbl/d in 2006.

Originally announced in the fall of 2005, the scoping study for the proposed Canadian Natural Upgrader, outside of the Horizon Project, continued during 2006 and into early 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the scoping study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and a narrowing Heavy Differential in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

In 2007, the Company's overall drilling activity in North America is expected to comprise approximately 423 natural gas wells and 813 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 expected to commence in the second half of 2008 at 110,000 bbl/d of 34° API SCO. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure. Extensive front end design and the high degree of project definition have enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. The high degree of up front project engineering and pre-planning is expected to reduce the risks associated with scope changes.

The Horizon Project continued on schedule and on budget with construction 57% complete at year end. The project status as at December 31, 2006 was as follows:

- Detailed engineering was 94% complete;
- Over $5.1 billion in purchase orders and contracts have been awarded to date;

- Several key mechanical contracts, including general mechanical contracts for the hydrotreater and cogeneration areas, were awarded;
- Set 333 pipe rack modules, essentially forming the core infrastructure of the plant;
- Mine overburden removal was approximately 35% complete; and
- Site preparation and underground infrastructure was completed.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

NORTH SEA

In 2006, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2006, 9.2 net wells were drilled with an additional 4 net wells drilling at year end.

The development of the Lyell Field progressed during the year with the completion of construction, installation and tie-in of subsea infrastructure. Tranche 1 of the Lyell Field development comprises the drilling of 4 net wells and the workover of 2 existing wells. Production from the Lyell Field is expected to be at full capacity in the second half of 2007.

During 2006, construction of the Columba E Raw Water Injection project continued. The project consists of 2 injection wells.

OFFSHORE WEST AFRICA

During 2006, 5.8 net wells were drilled with 1 well drilling at year-end.

First crude oil from West Espoir commenced from 3 wells brought on-line during 2006. Late in the year 2 water injector wells were added. The West Espoir area development drilling will continue until 2008 with producer and injector wells being brought on-line as they are completed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in October 2005, received Government approval of its development plan for this acquisition early in 2006 and received Board sanction for development in November 2006. Development plans include a FPSO handling input from 4 shallow-water producing platforms. Late in 2006 the Company signed a lease agreement for a FPSO with a primary term of ten years, commencing 2008.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2006	2005	2004
Working capital deficit [(1)]	$ 832	$ 1,774	$ 652
Long-term debt	$ 11,043	$ 3,321	$ 3,538
Shareholders' equity			
Share capital	$ 2,562	$ 2,442	$ 2,408
Retained earnings	8,141	5,804	4,922
Foreign currency translation adjustment	(13)	(9)	(6)
Total	$ 10,690	$ 8,237	$ 7,324
Debt to book capitalization [(2)]	50.8%	28.7%	33.8%
Debt to market capitalization	24.8%	9.7%	21.4%
After tax return on average common shareholders' equity [(3)]	26.9%	14.3%	21.4%
After tax return on average capital employed [(4)]	17.2%	10.4%	15.3%

(1) Calculated as current assets less current liabilities.
(2) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(3) Calculated as net earnings for the year as a percentage of average common shareholders' equity for the year.
(4) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year.

The Company's capital resources at December 31, 2006 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 five- and ten-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, Baa2 with a stable outlook by Moody's Investor Services, Inc. and BBB with a stable outlook by Standard and Poors Corporation.

At December 31, 2006, the Company had undrawn bank lines of credit of $1,115 million. Details related to the Company's credit facilities outstanding at December 31, 2006 are disclosed in note 5 to the Company's audited annual consolidated financial statements.

At December 31, 2006, the Company's working capital deficit was $832 million and included the current portion of the stock-based compensation liability of $611 million and the current portion of the net mark-to-market asset for non-designated risk management financial derivative instruments of $88 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 financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

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. Existing proved development projects, which have largely been funded prior to December 31, 2006, such as Baobab, Primrose and West Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Primarily due to the additional debt issued to complete the ACC acquisition, long-term debt increased to $11,043 million at December 31, 2006, resulting in a debt to book capitalization level of 50.8% as at December 31, 2006 (December 31, 2005 - 28.7%). While this ratio is above 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 2008. While the Company believes that its balance sheet has the strength and flexibility to accommodate the ACC acquisition, to ensure balance sheet strength going forward, the Company has hedged a significant portion of its natural gas and crude oil production for 2007 and 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of 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 expenditure program 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 expected 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 expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

In addition to the strategic location of the assets that ACC brings to the Company, this acquisition allows the Company to further high grade its project inventory and focus capital expenditures in the current highly inflationary service market. As a result of the acquisition, the Company has reduced its 2007 conventional crude oil and natural gas capital budget by $900 million compared to 2006 capital spending, while maintaining the capital expenditures to complete Phase I of the Horizon Project.

LONG-TERM DEBT

The Company's long-term debt of $11,043 million at December 31, 2006 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, 2006 the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are fully revolving for a period of five years maturing June 2011. 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, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

During 2006, the Company obtained a $500 million credit facility repayable on demand.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2006, was 4.8% (2005 – 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

MEDIUM-TERM NOTES

In January 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. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

SENIOR UNSECURED NOTES

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes due December 19, 2005.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES

In August 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 interest-rate 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 November 2006, the US shelf prospectus, filed in June 2005, was increased from US$2,000 million to US$3,000 million, leaving US$2,300 million available for issue in the United States until July 2007.

Subsequently, on March 12, 2007, the Company priced, for settlement on March 19, 2007, US$2,200 million of unsecured notes under the US shelf prospectus, 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 interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on 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 interest-rate 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. Net proceeds on the debt issue will be used to repay outstanding amounts under the Company's bank credit facilities.

SHARE CAPITAL

As at December 31, 2006, there were 537,903,000 common shares outstanding and 34,425,000 stock options outstanding. As at March 13, 2007, the Company had 538,970,000 common shares outstanding and 31,098,000 stock options outstanding.

During 2006, the Company purchased 485,000 common shares for cancellation (2005 – 850,000 common shares; 2004 – 873,400 common shares) at an average price of $57.33 per common share (2005 – $53.29 per common share; 2004 - $38.01 per common share), for a total cost of $28 million (2005 – $45 million; 2004 - $33 million) pursuant to the Normal Course Issuer Bids previously filed.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 15, 2007, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

In March 2007, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.34 per common share for 2007. The increase represented a 13% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the seventh consecutive year in which the Company has paid dividends and the sixth 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 February 2006, an increase in the annual dividend paid by the Company was approved to $0.30 per common share for 2006. The increase represented a 27% increase from the prior year.

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 office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to AROs. As at December 31, 2006, no entities have been consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2006:

($ millions)	2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$ 1,042
Offshore equipment operating leases (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,480
Long-term debt (4)	$ 161	$ 45	$ 3,876	$ –	$ 466	$ 3,713
Office leases	$ 26	$ 32	$ 33	$ 34	$ 22	$ –
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ –

(1) The Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) 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. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) Amounts represent management's estimate of the future undiscounted payments to settle AROs related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(4) The long-term debt represents principal repayments only. No debt repayments are reflected for $2,782 million of revolving bank credit facilities due to the extendable nature of the facilities.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

LEGAL PROCEEDINGS

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

RESERVES

For the year ended December 31, 2006, 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, natural gas liquids ("NGL") and natural gas reserves[1] 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 two principal differences between the two standards. The first is the additional 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 Company has disclosed 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 this 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 voluntary additional information, which is disclosed in the Company's most recent Annual Information Form.

For the year ended December 31, 2006, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("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 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, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

Additional reserves disclosure is contained in the supplementary oil and gas information of this Annual Report and in the Company's most recent Annual Information Form.

(1) Conventional crude oil, NGLs and natural gas includes all of the Company's light/medium, heavy, and thermal crude oil, natural gas, coal bed methane and natural gas liquids 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.

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. These inherent risks include, but are not limited to, the following items:

- Economic risk of finding and producing 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, AROs and depletion rates;
- Pricing risk of marketing reserves at an acceptable price given current market conditions;
- 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 at commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates, as the majority of sales are based in US dollars;
- Environmental impact risk associated with exploration and development activities;
- 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 international operations; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help 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 regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. 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 risks by only entering into sales contracts and financial derivatives with highly rated entities and financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Refer to the "Risk management activities" section of this MD&A. In addition, 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.

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 most recent 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. This will include dismantling production facilities and remediating damage caused by the disposal or release of specified substances. 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"), a detailed copy of which is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

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

- An annual 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; and
- A program to replace the majority of fresh water for steaming with brackish water.

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

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

In 2006, the Company's capital expenditures included $75 million for abandonment expenditures, an increase from $46 million in 2005 (2004 – $32 million).

The Company's estimated undiscounted ARO at December 31, 2006 was as follows:

Estimated ARO, undiscounted ($ millions)	2006	2005
North America	$ 2,826	$ 2,050
North Sea	1,543	1,185
Offshore West Africa	128	90
	4,497	3,325
North Sea PRT recovery	(625)	(370)
	$ 3,872	$ 2,955

The estimate of the 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 $625 million (2005 – $370 million, 2004 – $600 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 abandonment liability to $3,872 million (2005 – $2,955 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company is concurrently working with legislators and regulators on the design of new greenhouse gas emission laws and regulations and is pursuing an integrated emissions reduction strategy, to ensure the Company 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 climate change 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.

The Company continues to work with Canadian Federal and Provincial governments on the regulatory framework for greenhouse gases for larger emitters. The Company is actively promoting a harmonized regulatory framework between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2007 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008 and possibly a part of 2007 for larger facilities in Alberta.

Issues to be resolved include, but are not limited to: the outcome of discussions between the Federal and Provincial Governments, the impact of implementing legislation, the allocations of reduction obligations among industry sectors and international developments.

Any required reductions in the greenhouse gases emitted from the Company's operations could 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.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the Company's financial position and reported results of operations. 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country. 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 2006, 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, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. 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 based on experience.

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 is capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.7%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the 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) 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 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. Accounting for income taxes is an inherently complex process that requires management to interpret frequently changing regulations (e.g. changing income tax rates) and make certain judgements with respect to the application of tax law. 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 instruments to manage its commodity price, currency and interest rate exposures. These derivative and financial instruments are not intended for trading or speculative purposes.

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications. The cash settlement amount of the 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, 2006.

Effective January 1, 2007, the Company will adopt new accounting standards relating to the accounting for and disclosure of financial instruments. The estimated effects on the Company's consolidated balance sheet are discussed in further detail on page 68 of this MD&A.

PURCHASE PRICE ALLOCATIONS

The costs of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

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

CONTROL ENVIRONMENT

The Company's management, including the President and 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, 2006, 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, 2006, 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 2006 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, 2007, the Company will adopt the following new accounting standards relating to the accounting for and disclosure of financial instruments:

- 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 those resulting from investments by owners and distributions to owners.

  Foreign currency translation adjustment, which is currently a separate component of shareholders' equity, will be 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. Financial statements of prior periods will be restated only for the foreign currency translation adjustment.
- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This section also specifies how financial instruments gains and losses are to be presented.

  The Company will add all transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability to the fair value of the financial asset or financial liability. These adjustments were previously recorded in deferred charges. Transaction costs added to the fair value of the financial asset or financial liability will be amortized using the effective interest method.

- 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 this standard will require the Company to record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet will be recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

  Subsequently, if the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

Adoption of these standards will have the following estimated effects on the Company's consolidated balance sheet as at January 1, 2007:

($ millions)		
Decrease future income tax asset	$	(62)
Increase current portion of other long-term assets	$	193
Decrease other long-term assets	$	(16)
Decrease long-term debt	$	(72)
Increase future income tax liability	$	18
Increase retained earnings	$	10
Increase foreign currency translation adjustment	$	13
Increase accumulated other comprehensive income	$	146

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 high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of 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 2007 to average between 315,000 bbl/d and 360,000 bbl/d of crude oil and NGLs and between 1,594 mmcf/d and 1,664 mmcf/d of natural gas.

The forecasted capital expenditures in 2007 are currently expected to be as follows:

($ millions)	2007 Forecast
North America natural gas	$ 1,111
North America crude oil and NGLs	1,350
North Sea	521
Offshore West Africa	114
Property acquisitions and midstream	16
	3,112
Horizon Project Phase 1 construction (1)	2,610
Capitalized interest and other items	397
Horizon Project Phases 2/3 engineering	109
Canadian Natural Upgrader engineering	5
Total	$ 6,233

(1) Forecast to be in the range of $2,410 million to $2,810 million, the final level of expenditure will be dependent upon the ability of certain contractors to advance portions of their efforts from 2008 into 2007 as well as the extent of any realized cost pressures on certain isolated portions of the Horizon Project.

NORTH AMERICA NATURAL GAS

The 2007 North America natural gas drilling program is highlighted by the high-grading of the Company's natural gas asset base, including the properties acquired through the ACC acquisition, as follows:

(number of wells)	2007 Forecast
Northeast British Columbia	58
Northwest Alberta	123
Northern Plains	172
Southern Plains	70
Total	423

NORTH AMERICA CRUDE OIL AND NGLS

The 2007 North America crude oil drilling program is highlighted by continued development of its Primrose thermal projects, Pelican Lake, and a strong conventional heavy program, as follows:

(number of wells)	2007 Forecast
Conventional heavy crude oil	369
Thermal heavy crude oil	58
Light crude oil	107
Pelican Lake crude oil	132
Total	666

The Company has reduced forecasted natural gas capital for 2007 by approximately 40% from 2006 levels due to the shift in capital allocation to higher return crude oil projects in the near term. Allocation of natural gas capital between existing and newly acquired ACC lands will be the result of a high-grading process focusing on the highest return projects. No changes to the long-term natural gas plans of the Company are being contemplated.

The Company continues the disciplined development of its heavy crude oil resources. Crude oil capital has been maintained with 2006 levels as the Company continues to develop long-term production growth projects at Pelican Lake and in-situ oilsands at Primrose and Kirby.

THE HORIZON PROJECT

The final level of capital expenditure on the Horizon Project will be dependent upon the ability of certain of the contractors to advance portions of their efforts from 2008 into 2007, as well as the extent of any realized cost pressures on certain isolated portions of the project.

The 2007 capital forecast for the Horizon Project targets the completion of most major plants with the commissioning process to be substantially underway. The Ore Preparation Plant and Tailings Systems are targeted to be mechanically complete and ready to commission with the majority of utilities and offsite systems operational. The Upgrader is targeted to be nearing completion, with half of the related plants completed. A total of 156 stratigraphic test wells are targeted to be drilled on the Horizon Project leases during 2007.

NORTH SEA

The 2007 capital forecast for the North Sea includes drilling 7.4 producer wells and 7.2 service wells. The development of the Lyell Field is targeted for completion in late 2007.

OFFSHORE WEST AFRICA

The 2007 capital forecast for Offshore West Africa includes drilling 3.0 producer wells and 1.2 service well at West Espoir.

SENSITIVITY ANALYSIS (1)

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 2006, 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 ($/share, basic)	Net earnings ($ millions)	Net earnings ($/share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (2)				
Excluding financial derivatives	$ 116	$ 0.22	$ 81	$ 0.15
Including financial derivatives	$ 26-110	$ 0.05-0.21	$ 20-77	$ 0.04-0.14
Natural gas – AECO C$0.10/mcf (2)				
Excluding financial derivatives	$ 26	$ 0.05	$ 14	$ 0.03
Including financial derivatives	$ 1-8	$ 0.00-0.02	$ 2-4	$ 0.00-0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 98	$ 0.18	$ 44	$ 0.08
Natural gas – 10 mmcf/d	$ 17	$ 0.03	$ 6	$ 0.01
Foreign currency rate change				
$0.01 change in C$ in relation to US$ (2)				
Excluding financial derivatives	$ 80-82	$ 0.15	$ 23-24	$ 0.04
Interest rate change – 1%	$ 48	$ 0.09	$ 48	$ 0.09

(1) The sensitivities are calculated based on 2006 fourth quarter results and exclude mark-to-market gains (losses) on risk management activities.
(2) For details of financial instruments in place, refer to note 12 to the Company's audited annual consolidated financial statements as at December 31, 2006.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2006	2005	2004
Crude oil and NGLs (bbl/d)							
North America	**222,955**	**234,780**	**233,440**	**249,565**	**235,253**	221,669	206,225
North Sea	**60,802**	**63,703**	**53,988**	**61,786**	**60,056**	68,593	64,706
Offshore West Africa	**39,905**	**40,369**	**34,237**	**32,354**	**36,689**	22,906	11,558
Total	**323,662**	**338,852**	**321,665**	**343,705**	**331,998**	313,168	282,489
Natural gas (mmcf/d)							
North America	**1,411**	**1,448**	**1,416**	**1,594**	**1,468**	1,416	1,330
North Sea	**17**	**17**	**11**	**16**	**15**	19	50
Offshore West Africa	**8**	**10**	**10**	**10**	**9**	4	8
Total	**1,436**	**1,475**	**1,437**	**1,620**	**1,492**	1,439	1,388
Barrels of oil equivalent (boe/d)							
North America	**458,158**	**476,143**	**469,440**	**515,313**	**479,891**	457,695	427,936
North Sea	**63,589**	**66,426**	**55,790**	**64,490**	**62,558**	71,651	73,093
Offshore West Africa	**41,280**	**42,042**	**35,922**	**33,961**	**38,275**	23,614	12,806
Total	**563,027**	**584,611**	**561,152**	**613,764**	**580,724**	552,960	513,835

PER UNIT RESULTS (1)

	Q1	Q2	Q3	Q4	2006	2005	2004
Crude oil and NGLs ($/bbl)							
Sales price (2)	$ 43.79	$ 60.05	$ 62.55	$ 47.27	$ 53.65	$ 46.86	$ 37.99
Royalties	3.48	5.14	5.11	4.10	4.48	3.97	3.16
Production expense	11.33	11.92	13.47	12.32	12.29	11.17	10.05
Netback	$ 28.98	$ 42.99	$ 43.97	$ 30.85	$ 36.88	$ 31.72	$ 24.78
Natural gas ($/mcf)							
Sales price (2)	$ 8.30	$ 6.16	$ 5.83	$ 6.66	$ 6.72	$ 8.57	$ 6.50
Royalties	1.70	1.11	1.11	1.26	1.29	1.75	1.35
Production expense	0.80	0.80	0.84	0.86	0.82	0.73	0.67
Netback	$ 5.80	$ 4.25	$ 3.88	$ 4.54	$ 4.61	$ 6.09	$ 4.48
Barrels of oil equivalent ($/boe)							
Sales price (2)	$ 46.30	$ 50.36	$ 51.21	$ 43.91	$ 47.92	$ 48.77	$ 38.45
Royalties	6.44	5.80	5.75	5.62	5.89	6.82	5.37
Production expense	8.46	8.85	10.01	9.16	9.14	8.21	7.35
Netback	$ 31.40	$ 35.71	$ 35.45	$ 29.13	$ 32.89	$ 33.74	$ 25.73

(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)	2006	2005	2004
Sales price (2)	$ 47.92	$ 48.77	$ 38.45
Royalties	5.89	6.82	5.37
Production expense (3)	9.14	8.21	7.35
Netback	32.89	33.74	25.73
Midstream contribution (3)	(0.23)	(0.26)	(0.26)
Administration (4)	0.85	0.75	0.66
Interest, net	0.66	0.74	1.01
Realized risk management activities	6.27	5.13	2.52
Realized foreign exchange (gain) loss	(0.06)	(0.15)	0.02
Taxes other than income tax – current	1.04	1.01	1.12
Current income tax – North America	0.68	0.50	0.53
Current income tax – North Sea	0.14	0.77	0.01
Current income tax – Offshore West Africa	0.23	0.17	0.07
Cash flow	$ 23.31	$ 25.08	$ 20.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Excluding inter-segment eliminations.
(4) Restated to conform to current year presentation.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2006 Total	2005 Total
TSX – C$						
Trading volume (thousands)	134,487	129,036	127,022	118,390	508,935	637,992
Share price ($/share)						
High	$ 73.91	$ 72.70	$ 63.30	$ 63.50	$ 73.91	$ 62.00
Low	$ 57.75	$ 50.78	$ 47.28	$ 45.49	$ 45.49	$ 24.28
Close	$ 64.90	$ 61.72	$ 50.94	$ 62.15	$ 62.15	$ 57.63
Market capitalization at December 31 ($ millions)					$ 33,431	$ 30,910
Shares outstanding (thousands)					537,903	536,348
NYSE – US$						
Trading volume (thousands)	78,836	102,472	101,438	119,163	401,909	251,554
Share price ($/share)						
High	$ 64.38	$ 63.93	$ 56.68	$ 55.48	$ 64.38	$ 54.05
Low	$ 49.62	$ 45.67	$ 42.38	$ 40.29	$ 40.29	$ 19.74
Close	$ 55.39	$ 55.38	$ 45.58	$ 53.23	$ 53.23	$ 49.62
Market capitalization at December 31 ($ millions)					$ 28,633	$ 26,614
Shares outstanding (thousands)					537,903	536,348

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, 2006;
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2006; and
- management's assessment of the Company's internal control over financial reporting as at December 31, 2006.

Their report is presented with the consolidated financial statements.

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

Steve W. Laut
President & Chief Operating Officer

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

Randall S. Davis, CA
Vice President, Finance & Accounting

March 15, 2007
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 Rule 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, 2006. 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.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as at December 31, 2006, has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report presented with the audited consolidated financial statements.

Steve W. Laut
President & Chief Operating Officer

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

March 15, 2007
Calgary, Alberta, Canada

Independent Auditor's Report

To the Shareholders of Canadian Natural Resources Limited

We have completed an integrated audit of the consolidated financial statements and internal control over financial reporting of Canadian Natural Resources Limited (the "Company") as of December 31, 2006 and audits of its December 31, 2005 and December 31, 2004 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 of December 31, 2006 and December 31, 2005, and the related consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2006. 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 audit of the Company's financial statements as of December 31, 2006 and for the year 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 audits of the Company's financial statements as of December 31, 2005 and for each of the two years in the period 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.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and December 31, 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited management's assessment, included in the accompanying management's assessment of internal control over financial reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express opinions on management's assessment and 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
March 15, 2007

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 23**	$ 18
Accounts receivable and other	**1,947**	1,546
Future income tax (note 8)	**163**	487
Current portion of other long-term assets (note 3)	**106**	–
	2,239	2,051
Property, plant and equipment (note 4)	**30,767**	19,694
Other long-term assets (note 3)	**154**	107
	$ 33,160	$ 21,852
LIABILITIES		
Current liabilities		
Accounts payable	**$ 842**	$ 573
Accrued liabilities	**1,618**	1,781
Current portion of other long-term liabilities (note 6)	**611**	1,471
	3,071	3,825
Long-term debt (note 5)	**11,043**	3,321
Other long-term liabilities (note 6)	**1,393**	1,434
Future income tax (note 8)	**6,963**	5,035
	22,470	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 9)	**2,562**	2,442
Retained earnings	**8,141**	5,804
Foreign currency translation adjustment (note 10)	**(13)**	(9)
	10,690	8,237
	$ 33,160	$ 21,852

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)	2006	2005	2004
Revenue	**$ 11,643**	$ 11,130	$ 8,269
Less: royalties	**(1,245)**	(1,366)	(1,011)
Revenue, net of royalties	**10,398**	9,764	7,258
Expenses			
Production	**1,949**	1,663	1,400
Transportation and blending	**1,443**	1,293	972
Depletion, depreciation and amortization	**2,391**	2,013	1,769
Asset retirement obligation accretion (note 6)	**68**	69	51
Administration	**180**	151	125
Stock-based compensation (note 6)	**139**	723	249
Interest, net	**140**	149	189
Risk management activities (note 12)	**312**	1,952	434
Foreign exchange loss (gain)	**122**	(132)	(91)
	6,744	7,881	5,098
Earnings before taxes	**3,654**	1,883	2,160
Taxes other than income tax (note 8)	**256**	194	165
Current income tax (note 8)	**222**	286	116
Future income tax (note 8)	**652**	353	474
Net earnings	**$ 2,524**	$ 1,050	$ 1,405
Net earnings per common share (note 11)			
Basic	**$ 4.70**	$ 1.96	$ 2.62
Diluted	**$ 4.70**	$ 1.95	$ 2.60

Consolidated Statements of Retained Earnings

For the years ended December 31 (millions of Canadian dollars)	2006	2005	2004
Balance – beginning of year	**$ 5,804**	$ 4,922	$ 3,650
Net earnings	**2,524**	1,050	1,405
Dividends on common shares (note 9)	**(161)**	(127)	(107)
Purchase of common shares under Normal Course Issuer Bid (note 9)	**(26)**	(41)	(26)
Balance – end of year	**$ 8,141**	$ 5,804	$ 4,922

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	2006	2005	2004
Operating activities			
Net earnings	$ 2,524	$ 1,050	$ 1,405
Non-cash items			
Depletion, depreciation and amortization	2,391	2,013	1,769
Asset retirement obligation accretion	68	69	51
Stock-based compensation	139	723	249
Unrealized risk management activities	(1,013)	925	(40)
Unrealized foreign exchange loss (gain)	134	(103)	(94)
Deferred petroleum revenue tax expense (recovery)	37	(9)	(45)
Future income tax	652	353	474
Deferred charges	(2)	(31)	(33)
Abandonment expenditures	(75)	(46)	(32)
Net change in non-cash working capital (note 14)	(679)	(147)	(14)
	4,176	4,797	3,690
Financing activities			
Issue (repayment) of bank credit facilities	6,499	(435)	357
Issue (repayment) of medium-term notes	400	400	(125)
Repayment of senior unsecured notes	–	(194)	(54)
Issue of US dollar debt securities	788	–	830
Repayment of preferred securities	–	(107)	–
Repayment of obligations under capital leases	–	–	(7)
Issue of common shares on exercise of stock options	21	9	24
Dividends on common shares	(153)	(121)	(101)
Purchase of common shares	(28)	(45)	(33)
Net change in non-cash working capital (note 14)	37	19	6
	7,564	(474)	897
Investing activities			
Expenditures on property, plant and equipment	(7,266)	(5,340)	(4,582)
Net proceeds on sale of property, plant and equipment	71	454	7
Net expenditures on property, plant and equipment	(7,195)	(4,886)	(4,575)
Acquisition of Anadarko Canada Corporation (note 2)	(4,641)	–	–
Net proceeds on sale of other assets	–	11	–
Net change in non-cash working capital (note 14)	101	542	(88)
	(11,735)	(4,333)	(4,663)
Increase (decrease) in cash and cash equivalents	5	(10)	(76)
Cash and cash equivalents – beginning of year	18	28	104
Cash and cash equivalents – end of year	$ 23	$ 18	$ 28

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 operations are focused in North America, largely in Western Canada, the United Kingdom portion of the North Sea and Offshore West Africa. Within Western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to produce synthetic crude oil through mining and upgrading operations, while the midstream activities include the Company's 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 16.

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 ceiling test 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. Substantially all of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows 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 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

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 phase of 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

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

Property acquisition, construction and development costs related to the Company's Horizon Project are not accounted for under the full cost method of accounting and accordingly, are excluded from the Company's Canadian conventional oil and gas cost centre. Construction costs are capitalized separately to each phase of the Horizon Project. The Company will review the recoverability of the carrying amount of the Horizon Project costs if events or circumstances indicate that the carrying amount may not be recoverable.

(E) DEPLETION, DEPRECIATION AND AMORTIZATION

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 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 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.

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.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

(F) CAPITALIZED INTEREST

Following the Board of Directors' approval of Phase 1 of the Horizon Project in 2005, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization on Phase 1 will cease once construction is substantially complete and this phase of the Horizon Project is available for its intended use. The Company will continue to capitalize a portion of interest costs related to subsequent phases of the Horizon Project.

(G) DEFERRED CHARGES

Deferred charges primarily include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument. Refer to policy note (R) for the effect of new financial instrument policies on deferred charges.

(H) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms and gathering systems 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 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.

(I) 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 the foreign currency translation adjustment 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 are included in the consolidated statement of earnings. Gains or losses on the translation of foreign currency balances are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 10) for translation gains or losses for that portion of the US dollar denominated debt designated as a hedge of the net investment in self-sustaining foreign operations.

(J) 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.

(K) 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.

(L) 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 revenues and profit revenues. Cost recovery revenues allow the Company to recover its share and the government's share of capital and operating costs carried by the Company. Profit revenues are allocated to the Company in accordance with its respective equity interest, after a portion has been allocated to the government. Cost recovery and profit revenues are reported as sales revenues. The government's share of revenues attributable to the Company's equity interest, except for income tax, is reported as a royalty expense in accordance with the PSCs.

(M) PETROLEUM REVENUE TAX

The Company accounts for the United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current reserves and anticipated 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.

(N) 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. 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 and amount of capital expenditures incurred in Canada in any particular year.

(O) 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 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 adjusted to capitalized costs 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.

(P) 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. Changes in fair value of derivative financial instruments formally designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not formally designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all derivative financial instruments 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 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. All realized and unrealized gains or losses on these contracts are included in risk management activities, regardless of whether or not these contracts have been formally designated as hedges.

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. Gains or losses on interest rate swap contracts formally designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

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. Gains or losses on the foreign exchange component of all cross-currency swap contracts are included in risk management activities. Gains or losses on the interest component of cross-currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

Risk management activities are included in operating activities in the consolidated statements of cash flows.

Refer to policy note (R) for the effect of new accounting standards related to the accounting for risk management activities.

(Q) 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.

(R) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

FINANCIAL INSTRUMENTS

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

- 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 those resulting from investments by owners and distributions to owners.

  Foreign currency translation adjustment, which is currently a separate component of shareholders' equity, will be 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. Financial statements of prior periods will be restated only for the foreign currency translation adjustment.

- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This section also specifies how financial instruments gains and losses are to be presented.

  The Company will include all transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability with the fair value of the financial asset or financial liability. These adjustments were previously recorded in deferred charges. Transaction costs included with the fair value of the financial asset or financial liability will be amortized using the effective interest method.

- 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 this standard will require the Company to record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet will be recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

  Subsequently, if the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in comprehensive income each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

Adoption of these standards will have the following estimated effects on the Company's consolidated balance sheet as at January 1, 2007:

Decrease future income tax asset	$	(62)
Increase current portion of other long-term assets	$	193
Decrease other long-term assets	$	(16)
Decrease long-term debt	$	(72)
Increase future income tax liability	$	18
Increase retained earnings	$	10
Increase foreign currency translation adjustment	$	13
Increase accumulated other comprehensive income	$	146

(S) COMPARATIVE FIGURES

Certain figures related to the presentation of gross revenues and gross transportation and blending provided for prior years have been reclassified to conform to the presentation adopted in 2006.

Common share data has been restated to reflect the two-for-one share split in May 2005.

2. BUSINESS COMBINATIONS

ANADARKO CANADA CORPORATION

In November 2006, the Company completed the acquisition of all of the issued and outstanding common shares of Anadarko Canada Corporation ("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 preliminary allocation of the net purchase price is subject to change as actual amounts are determined. The preliminary allocation of the net purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

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 share purchase price.

3. OTHER LONG-TERM ASSETS

	2006	2005
Deferred charges	$ 109	$ 107
Risk management (note 12)	128	–
Other	23	–
	260	107
Less: current portion	106	–
	$ 154	$ 107

4. PROPERTY, PLANT AND EQUIPMENT

	2006 Cost	2006 Accumulated depletion and depreciation	2006 Net	2005 Cost	2005 Accumulated depletion and depreciation	2005 Net
Crude oil and natural gas						
North America	$ 31,715	$ 9,836	$ 21,879	$ 22,258	$ 7,948	$ 14,310
North Sea	3,370	1,341	2,029	2,703	1,022	1,681
Offshore West Africa	1,685	481	1,204	1,547	294	1,253
Other	38	14	24	27	14	13
Horizon Project	5,350	–	5,350	2,169	–	2,169
Midstream	263	56	207	251	48	203
Head office	150	76	74	124	59	65
	$ 42,571	$ 11,804	$ 30,767	$ 29,079	$ 9,385	$ 19,694

During the year ended December 31, 2006, the Company capitalized administrative overhead of $41 million (2005 – $41 million, 2004 – $49 million) relating to exploration and development in the North Sea and Offshore West Africa and $456 million (2005 – $236 million, 2004 – $35 million) relating primarily to the Horizon Project in North America.

During the year ended December 31, 2006, the Company capitalized $196 million (2005 - $72 million, 2004 - $nil) 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:

	2006	2005
Crude oil and natural gas		
North America	$ 2,244	$ 1,372
North Sea	24	28
Offshore West Africa	84	182
Other	24	13
Horizon Project	5,350	2,169
	$ 7,726	$ 3,764

The Company has used the following estimated benchmark future prices ("escalated pricing") in its ceiling test prepared in accordance with Canadian GAAP, as at December 31, 2006:

	2007	2008	2009	2010	2011	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 65.73	$ 68.82	$ 62.42	$ 58.37	$ 55.20	2.0%
Hardisty Heavy 12° API (C$/bbl)	$ 42.98	$ 45.02	$ 40.74	$ 38.03	$ 35.90	2.0%
Edmonton Par (C$/bbl)	$ 74.10	$ 77.62	$ 70.25	$ 65.56	$ 61.90	2.0%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 63.73	$ 66.78	$ 60.34	$ 56.24	$ 53.04	2.0%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 7.85	$ 8.39	$ 7.65	$ 7.48	$ 7.63	2.0%
AECO (C$/mmbtu)	$ 7.72	$ 8.59	$ 7.74	$ 7.55	$ 7.72	2.0%
Huntingdon/Sumas (C$/mmbtu)	$ 7.48	$ 8.45	$ 7.60	$ 7.41	$ 7.58	2.0%

5. LONG-TERM DEBT

	2006	2005
Bank credit facilities		
Bankers' acceptances	$ 6,621	$ 122
Medium-term notes		
7.40% unsecured debentures due March 1, 2007	125	125
4.50% unsecured debentures due January 23, 2013	400	–
4.95% unsecured debentures due June 1, 2015	400	400
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2006 – US$93 million, 2005 – US$93 million)	108	108
US dollar debt securities		
7.80% due July 2, 2008 (2006 – US$8 million, 2005 – US$nil)	9	–
6.70% due July 15, 2011 (2006 – US$400 million, 2005 – US$400 million)	466	467
5.45% due October 1, 2012 (2006 – US$350 million , 2005 – US$350 million)	408	408
4.90% due December 1, 2014 (2006 – US$350 million, 2005 – US$350 million)	408	408
6.00% due August 15, 2016 (2006 – US$250 million, 2005 – US$nil)	291	–
7.20% due January 15, 2032 (2006 – US$400 million, 2005 – US$400 million)	466	467
6.45% due June 30, 2033 (2006 – US$350 million, 2005 – US$350 million)	408	408
5.85% due February 1, 2035 (2006 – US$350 million, 2005 – US$350 million)	408	408
6.50% due February 15, 2037 (2006 – US$450 million, 2005 – US$nil)	525	–
	$ 11,043	$ 3,321

BANK CREDIT FACILITIES

As at December 31, 2006, the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are fully revolving for a period of five years maturing June 2011. 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 (note 2), the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

During 2006, the Company obtained a $500 million credit facility repayable on demand.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2006, was 4.8% (2005 – 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

MEDIUM-TERM NOTES

In January 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. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

SENIOR UNSECURED NOTES

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes due December 19, 2005.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES

In August 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 interest-rate 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 November 2006, the US shelf prospectus, filed in June 2005, was increased from US$2,000 million to US$3,000 million, leaving US$2,300 million available for issue in the United States until July 2007.

Subsequently, on March 12, 2007, the Company priced, for settlement on March 19, 2007, US$2,200 million of unsecured notes under the US shelf prospectus, 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 interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on 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 interest-rate 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. Net proceeds on the debt issue will be used to repay outstanding amounts under the Company's bank credit facilities.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2007	$ 161
2008	$ 45
2009	$ 3,876
2010	$ –
2011	$ 466
Thereafter	$ 3,713

No debt repayments are reflected for $2,782 million of revolving bank credit facilities due to the extendable nature of the facilities.

6. OTHER LONG-TERM LIABILITIES

	2006	2005
Asset retirement obligations	$ 1,166	$ 1,112
Stock-based compensation	744	891
Risk management (note 12)	–	885
Other	94	17
	2,004	2,905
Less: current portion	611	1,471
	$ 1,393	$ 1,434

ASSET RETIREMENT OBLIGATIONS

At December 31, 2006, the Company's total estimated undiscounted costs to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was approximately $4,497 million (2005 – $3,325 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 an average credit-adjusted risk-free interest rate of 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	2006	2005	2004
Asset retirement obligations			
Balance – beginning of year	$ 1,112	$ 1,119	$ 897
Liabilities incurred	26	47	53
Liabilities acquired (note 2)	56	–	286
Liabilities settled	(75)	(46)	(32)
Asset retirement obligation accretion	68	69	51
Revision of estimates	(21)	(56)	(86)
Foreign exchange	–	(21)	(50)
Balance – end of year	$ 1,166	$ 1,112	$ 1,119

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.

	2006	2005	2004
Stock-based compensation			
Balance – beginning of year	$ 891	$ 323	$ 171
Stock-based compensation	139	723	249
Cash payment for options surrendered	(264)	(227)	(80)
Transferred to common shares	(101)	(29)	(38)
Capitalized to Horizon Project	79	101	21
Balance – end of year	744	891	323
Less: current portion of stock-based compensation	611	629	243
	$ 133	$ 262	$ 80

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% 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, 2006 was $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, 2006, these plan assets had a fair value of $54 million. The unregistered pension plans are unfunded and have a benefit obligation of $15 million at December 31, 2006.

8. TAXES

TAXES OTHER THAN INCOME TAX

	2006	2005	2004
Current petroleum revenue tax	$ 196	$ 181	$ 190
Deferred petroleum revenue tax	37	(9)	(45)
Provincial capital taxes and surcharges	23	22	20
	$ 256	$ 194	$ 165

INCOME TAX

The provision for income tax is as follows:

	2006	2005	2004
Current income tax			
Current income tax – North America	$ 143	$ 99	$ 101
Current income tax – North Sea	30	155	2
Current income tax – Offshore West Africa	49	32	13
	222	286	116
Future income tax	652	353	474
Income tax	$ 874	$ 639	$ 590

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:

	2006	2005	2004
Canadian statutory income tax rate	34.9%	38.0%	39.3%
Income tax provision at statutory rate	$ 1,275	$ 716	$ 849
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	131	309	221
Canadian resource allowance	(129)	(293)	(270)
Large Corporations Tax	(16)	16	11
Deductible UK petroleum revenue tax	(82)	(65)	(57)
Foreign tax rate differentials	92	(1)	(31)
North America income tax rate changes	(438)	(19)	(66)
UK income tax rate changes	110	–	–
Côte d'Ivoire income tax rate changes	(67)	–	–
Non-taxable portion of foreign exchange	5	(15)	(36)
Attributed Canadian Royalty Income	(27)	(21)	(4)
Other	20	12	(27)
Income tax	$ 874	$ 639	$ 590

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

	2006	2005
Future income tax liabilities		
Property, plant and equipment	$ 6,088	$ 3,960
Timing of partnership items	1,394	1,646
Unrealized foreign exchange gain on long-term debt	93	112
Risk management activities	40	–
Other	13	31
Future income tax assets		
Asset retirement obligations	(487)	(384)
Capital loss carryforwards	(85)	(79)
Attributed Canadian Royalty Income	–	(75)
Stock-based compensation	(232)	(300)
Risk management activities	–	(304)
Deferred petroleum revenue tax	(24)	(59)
Net future income tax liability	6,800	4,548
Less: current portion future income tax asset	(163)	(487)
Future income tax liability	$ 6,963	$ 5,035

During 2006, 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, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2004, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $66 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduces 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 is being phased out and a deduction for actual crown royalties paid is being phased in.

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

	2006		2005	
Common shares	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance – beginning of year	536,348	$ 2,442	536,361	$ 2,408
Issued upon exercise of stock options	2,040	21	837	9
Previously recognized liability on stock options exercised for common shares	–	101	–	29
Purchase of common shares under Normal Course Issuer Bid	(485)	(2)	(850)	(4)
Balance – end of year	537,903	$ 2,562	536,348	$ 2,442

NORMAL COURSE ISSUER BID

During 2006, the Company purchased 485,000 common shares for cancellation (2005 – 850,000 common shares, 2004 – 1,746,800 common shares) at an average price of $57.33 per common share (2005 – $53.29 per common share, 2004 - $19.00 per common share), for a total cost of $28 million (2005 – $45 million, 2004 - $33 million). Retained earnings was reduced by $26 million (2005 – $41 million, 2004 - $26 million), representing the excess of the purchase price of the common shares over their average carrying value.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 15, 2007, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

DIVIDEND POLICY

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

In March 2007, the Board of Directors set the Company's regular quarterly dividend at $0.085 per common share (2006 – $0.075 per common share, 2005 – $0.059 per common share).

SHARE SPLIT

The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. All common share and per common share amounts were restated to retroactively reflect the share split.

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.

The following table summarizes information relating to stock options outstanding at December 31, 2006 and 2005:

	2006		2005	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	30,510	$ 17.79	32,522	$ 12.37
Granted	13,084	$ 59.61	7,959	$ 32.51
Exercised for common shares	(2,040)	$ 10.67	(837)	$ 9.81
Surrendered for cash settlement	(5,180)	$ 12.60	(7,523)	$ 10.49
Forfeited	(1,949)	$ 37.51	(1,611)	$ 19.36
Outstanding – end of year	34,425	$ 33.77	30,510	$ 17.79
Exercisable – end of year	9,177	$ 14.73	8,677	$ 11.21

The range of exercise prices of stock options outstanding and exercisable at December 31, 2006 is 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	4,672	0.76	$ 9.71	3,603	$ 9.74
$10.00 – $19.99	9,807	2.20	$ 14.68	4,202	$ 13.78
$20.00 – $29.99	5,099	3.34	$ 25.41	957	$ 25.00
$30.00 – $39.99	1,227	3.79	$ 33.23	175	$ 33.24
$40.00 – $49.99	686	5.02	$ 46.50	69	$ 43.84
$50.00 – $59.99	7,033	4.81	$ 57.85	166	$ 55.14
$60.00 – $69.14	5,901	4.27	$ 61.70	5	$ 61.60
	34,425	3.17	$ 33.77	9,177	$ 14.73

10. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized loss on the Company's net investment in self-sustaining foreign operations. Commencing July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

	2006	2005
Balance – beginning of year	**$ (9)**	$ (6)
Unrealized loss on translation of net investment	**(4)**	(12)
Hedge of net investment with US dollar denominated debt, net of tax	**–**	9
Balance – end of year	**$ (13)**	$ (9)

11. NET EARNINGS PER COMMON SHARE

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

(thousands of shares)	**2006**	2005	2004 [(1)]
Weighted average common shares outstanding – basic	**537,339**	536,650	536,223
Assumed settlement of preferred securities with common shares [(2)]	**–**	1,775	4,461
Weighted average common shares outstanding – diluted	**537,339**	538,425	540,684
Net earnings	**$ 2,524**	$ 1,050	$ 1,405
Interest on preferred securities, net of tax [(2)]	**–**	4	5
Revaluation of preferred securities, net of tax [(2)]	**–**	(2)	(4)
Diluted net earnings	**$ 2,524**	$ 1,052	$ 1,406
Net earnings per common share			
Basic	**$ 4.70**	$ 1.96	$ 2.62
Diluted	**$ 4.70**	$ 1.95	$ 2.60

(1) Restated to reflect two-for-one share split in May 2005.
(2) The preferred securities were redeemed in September 2005.

12. FINANCIAL INSTRUMENTS

RISK MANAGEMENT

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications.

As at December 31, 2006 and 2005, the estimated fair values of non-designated financial derivatives were comprised as follows:

	2006		2005	
Asset (liability)	Risk management mark-to-market	Deferred revenue	Risk management mark-to-market	Deferred revenue
Balance – beginning of year	$ (877)	$ (8)	$ 66	$ (26)
Net cost of outstanding put options	455	–	190	–
Net change in fair value of outstanding derivative financial instruments	1,005	–	(943)	–
Amortization of deferred revenue	–	8	–	18
	583	–	(687)	(8)
Add: put premium financing obligations [1]	(455)	–	(190)	–
Balance – end of year	128	–	(877)	(8)
Less: current portion	88	–	(834)	(8)
	$ 40	$ –	$ (43)	$ –

(1) The Company has negotiated payment of put option premiums with various counter-parties 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:

	2006	2005	2004
Net realized risk management loss	$ 1,325	$ 1,027	$ 474
Net unrealized risk management (gain) loss	(1,013)	925	(40)
	$ 312	$ 1,952	$ 434

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).

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, stock-based compensation, and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information, appropriate valuation methodologies and 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.

The carrying value of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, stock-based compensation, and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments were as follows:

	2006		2005	
Asset (liability)	Carrying value	Fair value	Carrying value	Fair value
Derivative financial instruments	$ 583	$ 805	$ (687)	$ (1,700)
Fixed rate notes	$ (4,410)	$ (4,434)	$ (3,199)	$ (3,367)

COMMODITY PRICE RISK MANAGEMENT

The Company uses certain derivative financial instruments to manage its commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not intended for trading or other speculative purposes. The following summarizes instruments outstanding as at December 31, 2006:

	Remaining term	Volume	Average price	Index
Crude oil				
Crude oil price collars	Jan 2007 – Dec 2007	15,000 bbl/d	US$50.00 – US$66.25	Mayan Heavy
	Jan 2007 – Dec 2007	50,000 bbl/d	US$60.00 – US$71.49	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$60.00 – US$78.11	WTI
	Jan 2007 – Dec 2007	50,000 bbl/d	US$65.00 – US$84.52	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 (1)	Jan 2007 – Dec 2007	100,000 bbl/d	US$45.00	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$60.00	WTI
	Jan 2008 – Dec 2008	50,000 bbl/d	US$55.00	WTI
Brent differential swaps	Jan 2007 – Dec 2007	50,000 bbl/d	US$1.34	WTI/Dated Brent

The cost of outstanding put options and their respective years of settlement are as follows:

		2007		2008
Cost (1) ($ millions)	US$	331	US$	59

(1) Subsequent to December 31, 2006, the Company unwound 23,000 bbl/d of US$60.00 WTI put options for the period February 2007 to December 2007, for cash consideration of US$40 million.

	Remaining term	Volume	Average price	Index
Natural gas				
AECO collars	Jan 2007 – Mar 2007	100,000 GJ/d	C$7.00 – C$11.63	AECO
	Jan 2007 – Mar 2007	200,000 GJ/d	C$7.25 – C$8.38	AECO
	Jan 2007 – Mar 2007	162,500 GJ/d	C$7.25 – C$9.48	AECO
	Jan 2007 – Mar 2007	162,500 GJ/d	C$7.50 – C$8.94	AECO
	Jan 2007 – Mar 2007	300,000 GJ/d	C$7.50 – C$18.77	AECO
	Jan 2007 – Mar 2007	400,000 GJ/d	C$8.50 – C$11.22	AECO
	Jan 2007 – Dec 2007	60,000 GJ/d	C$8.00 – C$8.79	AECO
	Apr 2007 – Oct 2007	500,000 GJ/d	C$6.00 – C$10.13	AECO
	Apr 2007 – Oct 2007	500,000 GJ/d	C$7.00 – C$8.24	AECO
	Nov 2007 – Mar 2008	400,000 GJ/d	C$7.00 – C$14.08	AECO
	Nov 2007 – Mar 2008	500,000 GJ/d	C$7.50 – C$10.81	AECO

Commodity related derivative financial instruments designated as hedges at December 31, 2006, were all classified as cash flow hedges.

The Company's outstanding derivatives will be settled monthly based on the applicable index pricing for the respective contract month.

In addition to the financial derivatives noted above, the Company also entered into natural gas physical sales contracts for 325,000 GJ/d at an average fixed price of C$9.17 per GJ at AECO for the period January to March 2007 and 300,000 GJ/d at an average fixed price of C$7.33 per GJ at AECO for the period April 2007 to October 2007.

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

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, 2006, 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 2007 – Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Jan 2007 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2007 – Mar 2007	C$2	7.36%	CDOR (2)

(1) London Interbank Offered Rate
(2) Canadian Deposit Overnight Rate

Interest rate related derivative financial instruments designated as hedges at December 31, 2006, were all 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. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations (note 10). At December 31, 2006, 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 2007 – Aug 2016	US$250	1.116	6.00%	5.40%

Cross-currency related derivative financial instruments designated as hedges at December 31, 2006, were all 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 this risk by only entering into sales contracts with highly rated entities. In addition, 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.

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 only entering into agreements with highly rated financial institutions and other entities. At December 31, 2006, the Company had net risk management assets of $161 million with specific counterparties related to derivative financial instruments.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$ 1,042
Offshore equipment operating leases (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,480
Office leases	$ 26	$ 32	$ 33	$ 34	$ 22	$ –
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ –

(1) The Company has entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, the annual toll payments before operating costs will be approximately $35 million.

(2) 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. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) 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 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to 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:

		2006		2005		2004
(Increase) decrease in non-cash working capital						
Accounts receivable and other	$	(116)	$	(498)	$	(329)
Accounts payable		157		196		39
Accrued liabilities		(582)		716		194
Net change in non-cash working capital	$	(541)	$	414	$	(96)
Relating to:						
Operating activities	$	(679)	$	(147)	$	(14)
Financing activities		37		19		6
Investing activities		101		542		(88)
	$	(541)	$	414	$	(96)

Other cash flow information:		2006		2005		2004
Interest paid	$	262	$	200	$	192
Taxes paid	$	703	$	430	$	218

15. SEGMENTED INFORMATION

The Company's 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 crude oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from crude oil and natural gas activities. 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.

	Crude Oil and Natural Gas								
	North America			North Sea			Offshore West Africa		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Segmented revenue	**$ 9,066**	$ 8,955	$ 6,701	**$ 1,616**	$ 1,659	$ 1,317	**$ 950**	$ 485	$ 222
Less: royalties	**(1,203)**	(1,350)	(1,003)	**(3)**	(3)	(2)	**(39)**	(13)	(6)
Revenue, net of royalties	**7,863**	7,605	5,698	**1,613**	1,656	1,315	**911**	472	216
Segmented expenses									
Production	**1,436**	1,211	976	**390**	379	370	**106**	53	36
Transportation and blending	**1,465**	1,310	978	**15**	20	32	**1**	–	–
Depletion, depreciation and amortization	**1,897**	1,595	1,444	**297**	306	265	**189**	104	53
Asset retirement obligation accretion	**35**	34	28	**31**	34	22	**2**	1	1
Realized risk management activities	**1,022**	870	362	**303**	157	112	**–**	–	–
Total segmented expenses	**5,855**	5,020	3,788	**1,036**	896	801	**298**	158	90
Segmented earnings before the following	**$ 2,008**	$ 2,585	$ 1,910	**$ 577**	$ 760	$ 514	**$ 613**	$ 314	$ 126
Non-segmented expenses									
Administration									
Stock-based compensation									
Interest, net									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax									
Future income tax									
Net earnings									

	Midstream			Inter-segment elimination and other			Total		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
	$ 72	$ 77	$ 68	**$ (61)**	$ (46)	$ (39)	**$ 11,643**	$ 11,130	$ 8,269
	–	–	–	**–**	–	–	**(1,245)**	(1,366)	(1,011)
	72	77	68	**(61)**	(46)	(39)	**10,398**	9,764	7,258
	23	24	20	**(6)**	(4)	(2)	**1,949**	1,663	1,400
	–	–	–	**(38)**	(37)	(38)	**1,443**	1,293	972
	8	8	7	**–**	–	–	**2,391**	2,013	1,769
	–	–	–	**–**	–	–	**68**	69	51
	–	–	–	**–**	–	–	**1,325**	1,027	474
	31	32	27	**(44)**	(41)	(40)	**7,176**	6,065	4,666
	$ 41	$ 45	$ 41	**$ (17)**	$ (5)	$ 1	**3,222**	3,699	2,592
							180	151	125
							139	723	249
							140	149	189
							(1,013)	925	(40)
							122	(132)	(91)
							(432)	1,816	432
							3,654	1,883	2,160
							256	194	165
							222	286	116
							652	353	474
							$ 2,524	$ 1,050	$ 1,405

CAPITAL EXPENDITURES

	2006			2005		
	Cash expenditures	**Non-cash and fair value adjustments [1]**	**Capitalized costs**	Cash expenditures	Non-cash and fair value adjustments [1]	Capitalized costs
Crude oil and natural gas						
North America	**$ 7,936**	**$ 1,521**	**$ 9,457**	$ 2,530	$ (22)	$ 2,508
North Sea	**646**	**(14)**	**632**	387	(136)	251
Offshore West Africa	**134**	**1**	**135**	439	27	466
Other	**11**	**–**	**11**	5	–	5
	8,727	**1,508**	**10,235**	3,361	(131)	3,230
Horizon Project [2]	**3,185**	**–**	**3,185**	1,499	–	1,499
Midstream	**12**	**–**	**12**	4	–	4
Head office	**26**	**–**	**26**	22	–	22
	$ 11,950	**$ 1,508**	**$ 13,458**	$ 4,886	$ (131)	$ 4,755

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.
(2) Cash expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

Segmented property, plant and equipment, net	2006	2005
Crude oil and natural gas		
North America	$ 21,879	$ 14,310
North Sea	2,029	1,681
Offshore West Africa	1,204	1,253
Other	24	13
Horizon Project	5,350	2,169
Midstream	207	203
Head office	74	65
	$ 30,767	$ 19,694

Segmented assets	2006	2005
Crude oil and natural gas		
North America	$ 23,670	$ 15,939
North Sea	2,248	1,950
Offshore West Africa	1,323	1,371
Other	46	30
Horizon Project	5,444	2,239
Midstream	355	258
Head office	74	65
	$ 33,160	$ 21,852

16. 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	2006	2005	2004
Net earnings – Canadian GAAP		$ 2,524	$ 1,050	$ 1,405
Adjustments				
Depletion, net of tax of $1 million (2005 - $3 million, 2004 - $2 million)	(A,C)	2	4	4
Stock-based compensation, net of tax of $18 million (2005 - $nil, 2004 - $nil)	(B)	(40)	–	–
Derivative financial instruments and hedging activities, net of tax of $15 million (2005 - $11 million, 2004 - $7 million)	(C)	117	(19)	(9)
Capitalized interest, net of tax of $nil (2005 - $nil, 2004 - $11 million)	(D)	–	–	16
Net earnings before cumulative effect of change in accounting policy – US GAAP		2,603	1,035	1,416
Cumulative effect of change in accounting policy, net of tax of $3 million (2005 - $nil, 2004 - $nil)	(B)	(8)	–	–
Net earnings – US GAAP		$ 2,595	$ 1,035	$ 1,416
Net earnings before cumulative effect of change in accounting policy – US GAAP per common share				
Basic		$ 4.84	$ 1.93	$ 2.64
Diluted	(F)	$ 4.77	$ 1.88	$ 2.57
Net earnings – US GAAP per common share				
Basic		$ 4.83	$ 1.93	$ 2.64
Diluted	(F)	$ 4.75	$ 1.88	$ 2.57

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2006	2005	2004
Net earnings – US GAAP		$ 2,595	$ 1,035	$ 1,416
Derivative financial instruments and hedging activities, net of tax of $394 million (2005 - $312 million; 2004 - $3 million)	(C)	805	(635)	8
Foreign currency translation adjustment, net of tax of $nil (2005 - $2 million, 2004 - $4 million)	(E)	(4)	(3)	(9)
Comprehensive income		$ 3,396	$ 397	$ 1,415

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

		2006		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets	(C)	$ 2,239	$ 131	$ 2,370
Property, plant and equipment	(A,B,C,D)	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)	6,963	21	6,984
Share capital		2,562	–	2,562
Retained earnings		8,141	45	8,186
Foreign currency translation adjustment	(E)	(13)	13	–
Accumulated other comprehensive income	(C,E)	–	146	146
		$ 33,160	$ 249	$ 33,409

		2005		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets	(C)	$ 2,051	$ 338	$ 2,389
Property, plant and equipment	(A,D)	19,694	(20)	19,674
Other long-term assets		107	–	107
		$ 21,852	$ 318	$ 22,170
Current liabilities	(C)	$ 3,825	$ 1,005	$ 4,830
Long-term debt	(C)	3,321	(18)	3,303
Other long-term liabilities	(C)	1,434	8	1,442
Future income tax	(A,C,D)	5,035	(5)	5,030
Share capital		2,442	–	2,442
Retained earnings		5,804	(26)	5,778
Foreign currency translation adjustment	(E)	(9)	9	–
Accumulated other comprehensive income	(C,E)	–	(655)	(655)
		$ 21,852	$ 318	$ 22,170

NOTES:

(A) Under Canadian full cost accounting rules, costs capitalized in each 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, 2006, US GAAP net earnings would have increased by $3 million (2005 – $4 million, 2004 – $4 million), net of income taxes of $2 million (2005 – $3 million, 2004 – $2 million) to reflect the impact of lower depletion charges.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(O). 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, 2006 US GAAP net earnings would have decreased by $48 million, net of income taxes of $21 million, including the cumulative effect of the change in accounting policy of $8 million, net of income taxes of $3 million. There was no difference from Canadian GAAP prior to 2006.

(C) The Company accounts for its derivative financial instruments under Canadian GAAP as described in note 1(P). For US GAAP purposes, FAS 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149, establishes US GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in comprehensive income each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness of cash flow hedges are based on a combination of third party valuations and internally derived valuations. The Company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

For the year ended December 31, 2006, assets would have increased by $160 million (2005 - $338 million), liabilities would have decreased by $9 million (2005 – increased by $997 million), and accumulated other comprehensive income would have increased by $159 million (2005 – decreased by $646 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 would have been $29 million, net of income taxes of $15 million (2005 – loss of $19 million, net of income taxes of $11 million; 2004 – loss of $9 million, net of income taxes of $7 million). The company estimates that $122 million of after-tax hedging gains will be reclassified from accumulated other comprehensive income to current period earnings within the next twelve month period as a result of forecasted sales occurring.

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, the $88 million after-tax gain on the derivative financial instruments and related depletion expense of $1 million, net of income taxes of $1 million, would have been included in net earnings.

Accordingly, for the year ended December 31, 2006 US GAAP net earnings would have increased in total by $117 million, net of income taxes of $15 million (2005 – decreased net earnings of $19 million, net of income taxes of $11 million; 2004 – decreased net earnings of $9 million, net of income taxes of $7 million) to reflect the impact of derivative financial instruments.

(D) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. For the year ended December 31, 2004, $27 million would have been capitalized to property, plant and equipment for US GAAP.

(E) Under US GAAP, exchange losses of $4 million, net of income taxes of $nil (2005 - $3 million, net of income taxes of $2 million; 2004 - $9 million, net of income taxes of $4 million) arising from the translation of self-sustaining foreign operations would have been included in comprehensive income.

(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 since 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, 2006, an additional 8,762,000 shares would have been included in the calculation of diluted earnings per share for US GAAP (2005 – 13,593,000 additional shares, 2004 – 10,111,000 additional shares).

(G) Recently issued accounting standards under US GAAP:

UNCERTAIN TAX POSITIONS

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 Company is currently assessing the impact of FIN 48 on its consolidated financial statements.

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, 2006, 2005, and 2004 the reports by Sproule Associates Limited ("Sproule") and Ryder Scott Company covered 100% of the Company's conventional reserves;
- For the year ended December 31, 2003, the reports by Sproule 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, 2006, 2005, 2004 and 2003:

Crude oil and NGLs (mmbbl)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2003	588	222	85	895
Extensions and discoveries	17	–	–	17
Improved recovery	25	45	–	70
Purchases of reserves in place	36	38	–	74
Sales of reserves in place	–	–	–	–
Production	(66)	(24)	(4)	(94)
Revisions of previous estimates	48	22	34	104
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 previous 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 previous estimates	**(1)**	**2**	**9**	**10**
Reserves, December 31, 2006	**887**	**299**	**130**	**1,316**
Net proved developed reserves:				
December 31, 2003	348	138	23	509
December 31, 2004	367	218	20	605
December 31, 2005	402	214	80	696
December 31, 2006	**420**	**214**	**63**	**697**

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2003	2,426	62	64	2,552
Extensions and discoveries	334	–	–	334
Improved recovery	80	–	–	80
Purchases of reserves in place	182	10	–	192
Sales of reserves in place	(8)	–	–	(8)
Production	(383)	(18)	(3)	(404)
Revisions of previous estimates	(40)	(27)	11	(56)
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 previous 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 previous estimates	**(37)**	**13**	**(13)**	**(37)**
Reserves, December 31, 2006	**3,705**	**37**	**56**	**3,798**
Net proved developed reserves:				
December 31, 2003	2,140	46	12	2,198
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**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

(millions of Canadian dollars)	**2006** 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**

(millions of Canadian dollars)	2005 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

(millions of Canadian dollars)	2004 North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 18,722	$ 2,506	$ 563	$ 14	$ 21,805
Unproved properties	1,028	44	528	8	1,608
	19,750	2,550	1,091	22	23,413
Less: accumulated depletion and depreciation	(6,410)	(727)	(190)	(14)	(7,341)
Net capitalized costs	$ 13,340	$ 1,823	$ 901	$ 8	$ 16,072

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

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

2004 (millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 1,806	$ 530	$ –	$ –	$ 2,336
Unproved	298	4	–	–	302
Exploration	290	11	36	1	338
Development	1,443	235	259	–	1,937
Costs incurred	$ 3,837	$ 780	$ 295	$ 1	$ 4,913

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, 2006, 2005 and 2004 are summarized in the following tables:

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**

2005 (millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 5,727	$ 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

(millions of Canadian dollars)	2004 North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 4,579	$ 1,203	$ 216	$ 5,998
Production	(976)	(370)	(36)	(1,382)
Transportation	(256)	(32)	–	(288)
Depletion, depreciation and amortization	(1,438)	(265)	(53)	(1,756)
Asset retirement obligation accretion	(28)	(22)	(1)	(51)
Petroleum revenue tax	–	(145)	–	(145)
Income tax	(690)	(148)	(44)	(882)
Results of operations	$ 1,191	$ 221	$ 82	$ 1,494

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

(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

(millions of Canadian dollars)	2004 North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 31,727	$ 15,526	$ 5,249	$ 52,502
Future production costs	(10,995)	(6,302)	(1,137)	(18,434)
Future development and asset retirement obligations	(2,944)	(2,832)	(631)	(6,407)
Future income taxes	(6,438)	(3,783)	(1,242)	(11,463)
Future net cash flows	11,350	2,609	2,239	16,198
10% annual discount for timing of future cash flows	(4,385)	(691)	(634)	(5,710)
Standardized measure of future net cash flows	$ 6,965	$ 1,918	$ 1,605	$ 10,488

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)	**2006**	2005	2004
Sales of crude oil and natural gas produced, net of production costs	**$ (5,635)**	$ (5,785)	$ (4,331)
Net changes in sales prices and production costs	**(2,420)**	11,056	(553)
Extensions, discoveries and improved recovery	**4,769**	3,596	2,120
Changes in estimated future development costs	**(1,885)**	(971)	(894)
Purchases of proved reserves in place	**2,406**	469	1,386
Sales of proved reserves in place	**(2)**	(130)	(20)
Revisions of previous reserve estimates	**81**	961	1,431
Accretion of discount	**3,112**	1,812	1,558
Changes in production timing and other	**(2,156)**	1,414	1,357
Net change in income taxes	**1,270**	(4,458)	(997)
Net change	**(460)**	7,964	1,057
Balance – beginning of year	**18,452**	10,488	9,431
Balance – end of year	**$ 17,992**	$ 18,452	$ 10,488

Ten-Year Review

Years ended December 31	**2006**	2005	2004	2003	2002	2001	2000	1999	1998	1997
FINANCIAL INFORMATION										
(Cdn $ millions, except per share amounts)										
Net earnings	**2,524**	1,050	1,405	1,403	539	639	758	213	31	104
Per share - basic (1)	**$ 4.70**	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$ 0.51	$ 0.08	$ 0.26
Cash flow from operations (2)	**4,932**	5,021	3,769	3,160	2,254	1,920	1,884	724	444	503
Per share - basic (1)	**$ 9.18**	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$ 1.74	$ 1.12	$ 1.28
Capital expenditures, net of dispositions (including business combinations)	**12,025**	4,932	4,633	2,506	4,069	1,885	2,823	1,901	610	1,119
Balance Sheet information										
Working capital (deficiency) surplus	**(832)**	(1,774)	(652)	(505)	(14)	(6)	(77)	36	58	(19)
Property, plant and equipment, net	**30,767**	19,694	17,064	13,714	12,934	8,766	7,439	4,679	3,135	2,831
Total assets	**33,160**	21,852	18,372	14,643	13,793	9,290	8,051	4,976	3,329	3,016
Long-term debt	**11,043**	3,321	3,538	2,748	4,200	2,788	2,573	2,157	1,426	1,136
Shareholders' equity	**10,690**	8,237	7,324	6,006	4,754	3,928	3,297	1,962	1,317	1,250
SHARE INFORMATION										
Common shares outstanding (thousands)	**537,903**	536,348	536,361	534,926	535,104	484,804	489,116	445,816	399,236	395,276
Weighted average shares outstanding (thousands)	**537,339**	536,650	536,223	536,940	511,532	485,200	466,804	415,624	397,324	392,168
Dividends declared per common share	**$ 0.30**	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ –	$ –	$ –	$ –
Trading statistics (1)										
TSX - C$										
Trading volume (thousands)	**508,935**	637,992	606,024	590,702	619,316	534,976	567,412	430,460	410,440	402,152
Share Price ($/share)										
High	**$ 73.91**	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$ 9.65	$ 7.88	$ 11.06
Low	**$ 45.49**	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$ 4.95	$ 4.56	$ 7.23
Close	**$ 62.15**	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$ 8.81	$ 5.75	$ 7.65
NYSE - US$										
Trading volume (thousands)	**401,909**	251,554	125,468	46,916	31,864	20,764	3,172	–	–	–
Share Price ($/share)										
High	**$ 64.38**	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$ –	$ –	$ –
Low	**$ 40.29**	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$ –	$ –	$ –
Close	**$ 53.23**	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$ –	$ –	$ –
RATIOS										
Debt to book capitalization (3)	**50.8%**	28.7%	33.8%	32.8%	47.1%	41.7%	44.0%	52.4%	52.0%	47.6%
Return on average common shareholders' equity, after tax (3)	**26.9%**	14.3%	21.4%	25.6%	13.0%	17.7%	28.8%	13.0%	2.4%	8.8%
Daily production before royalties per thousand common shares (boe/d) (1)	**10.8**	10.3	9.6	8.5	8.2	7.4	6.6	5.0	4.7	4.5
Conventional proved and probable reserves per common share (boe) (1)(4)	**6.4**	4.8	4.3	4.0	3.3	3.1	2.9	2.4	1.9	1.7
Net asset value per common share (1)(5)	**$ 56.41**	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54	$ 12.33	$ 8.08	$ 6.80

(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.
(2) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on net earnings and cash flow. Cash flow from operations may not be comparable to similar measures used by other companies.
(3) Refer to the MD&A, page 60, "Liquidity and Capital Resources", 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 and 2006, $75/acre for all years prior, less long-term debt and existing asset liabilities and adjusted for working capital. See reserves disclosures on pages 37 to 41.

Years ended December 31	**2006**	2005	2004	2003	2002	2001	2000	1999	1998	1997
OPERATING INFORMATION										
Conventional crude oil and NGLs (mmbbl)										
Company gross proved reserves (before royalties)										
North America	**1,043**	785	695	672	665	644	643	554	284	257
North Sea	**299**	290	303	222	203	83	102	–	–	–
Offshore West Africa	**145**	148	125	106	94	61	36	–	–	–
	1,487	1,223	1,123	1,000	962	788	781	554	284	257
Company gross proved and probable reserves (before royalties)										
North America	**1,753**	1,154	992	977	742	740	731	640	380	329
North Sea	**421**	417	415	317	277	106	134	–	–	–
Offshore West Africa	**223**	230	214	187	162	111	46	–	–	–
	2,397	1,801	1,621	1,481	1,181	957	911	640	380	329
Conventional Natural gas (bcf)										
Company gross proved reserves (before royalties)										
North America	**4,507**	3,378	3,202	3,006	3,048	2,566	2,360	2,183	1,901	1,716
North Sea	**37**	29	27	62	71	94	91	–	–	–
Offshore West Africa	**69**	83	81	86	90	69	65	–	–	–
	4,613	3,490	3,310	3,154	3,209	2,729	2,516	2,183	1,901	1,716
Company gross proved and probable reserves (before royalties)										
North America	**5,898**	4,372	4,100	3,611	3,450	2,915	2,762	2,547	2,211	2,078
North Sea	**93**	69	57	101	89	118	114	–	–	–
Offshore West Africa	**121**	127	102	111	120	96	84	–	–	–
	6,112	4,568	4,259	3,823	3,659	3,129	2,960	2,547	2,211	2,078
Total proved reserves (before royalties) (mmboe)	**2,256**	1,804	1,674	1,526	1,497	1,243	1,200	918	601	543
Total proved and probable reserves (before royalties) (mmboe)	**3,416**	2,562	2,330	2,118	1,791	1,479	1,404	1,065	749	675
Oil Sands, mining (mmbbl)										
Gross proved and probable reserves (before royalties)										
Bitumen	**3,530**	3,430	–	–	–	–	–	–	–	–
Synthetic crude oil (1)	**2,962**	2,878	–	–	–	–	–	–	–	–
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America	**235**	222	206	175	169	167	155	87	76	71
North Sea	**60**	68	65	57	39	36	17	–	–	–
Offshore West Africa	**37**	23	12	10	7	3	2	–	–	–
	332	313	283	242	215	206	174	87	76	71
Natural gas (mmcf/d)										
North America	**1,468**	1,416	1,330	1,245	1,204	906	793	721	673	626
North Sea	**15**	19	50	46	27	12	1	–	–	–
Offshore West Africa	**9**	4	8	8	1	–	–	–	–	–
	1,492	1,439	1,388	1,299	1,232	918	794	721	673	626
Total production (before royalties) (mboe/d)	**581**	553	514	459	421	359	306	207	188	175
Product Pricing										
Average crude oil and NGLs price ($/bbl)	**53.65**	46.86	37.99	32.66	31.22	23.45	31.89	22.26	11.98	18.99
Average natural gas price ($/mcf)	**6.72**	8.57	6.50	6.21	3.77	5.45	4.92	2.52	2.11	1.97

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

Corporate Information

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President, Edco Financial Holdings Ltd.
Calgary, Alberta

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Consultant, Exchange Group
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Atlanta, Georgia

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

Steve W. Laut
President & Chief Operating Officer,
Canadian Natural Resources Limited
Calgary, Alberta

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Chairman, President & Chief Executive Officer,
Bonavista Energy Trust
Calgary, Alberta

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Canadian Natural Resources Limited
Calgary, Alberta

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Cap Pelé, New Brunswick

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Emeritus Professor and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

***David A. Tuer** (1) (3) (4 – Chair)
Executive Vice-Chairman, BA Energy Inc.
Calgary, Alberta

(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 independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

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
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Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

Corporate Offices

HEAD OFFICE

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

Telephone: (403) 517-6700
Facsimile: (403) 517-7350
Website: www.cnrl.com

INVESTOR RELATIONS

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com

INTERNATIONAL OFFICE

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

Corporate Governance

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

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 2006 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.

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Independent Qualified Reserves Evaluators

GLJ Petroleum Consultants
Calgary, Alberta

Ryder Scott Company
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

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Canadian Natural

Canadian Natural Resources Limited

2500, 855 - 2 Street SW
Calgary, Alberta
Canada T2P 4J8

Phone: 403.**517.6700**
Fax: 403.**517.7350**
www.cnrl.com

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