2008 Quarterly Report

PETRO-CANADA

July 24, 2008 (publié également en français)

For the six months ended June 30, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A), dated July 24, 2008, is set out in pages 1 to 24 and should be read in conjunction with the unaudited Consolidated Financial Statements of the Company for the three months ended March 31, 2008 and the three and six months ended June 30, 2008; the MD&A for the year ended December 31, 2007; the audited Consolidated Financial Statements for the year ended December 31, 2007, and the Company's 2007 Annual Information Form (AIF), dated March 17, 2008. Amounts are in Canadian (Cdn) dollars unless otherwise specified.

LEGAL NOTICE – FORWARD-LOOKING INFORMATION

This quarterly report contains forward-looking information. You can usually identify this information by such words as *"plan," "anticipate," "forecast," "believe," "target," "intend," "expect," "estimate," "budget"* or other terms that suggest future outcomes or references to outlooks. Listed below are examples of references to forward-looking information:

- business strategies and goals
- future investment decisions
- outlook (including operational updates and strategic milestones)
- future capital, exploration and other expenditures
- future cash flows
- future resource purchases and sales
- construction and repair activities
- turnarounds at refineries and other facilities
- anticipated refining margins
- future oil and natural gas production levels and the sources of their growth
- project development, and expansion schedules and results
- future exploration activities and results, and dates by which certain areas may be developed or come on-stream
- retail throughputs
- pre-production and operating costs
- reserves and resources estimates
- royalties and taxes payable
- production life-of-field estimates
- natural gas export capacity
- future financing and capital activities (including purchases of Petro-Canada common shares under the Company's normal course issuer bid (NCIB) program)
- contingent liabilities (including potential exposure to losses related to retail licensee agreements)
- environmental matters
- future regulatory approvals
- expected rates of return

Such forward-looking information is subject to known and unknown risks and uncertainties. Other factors may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such factors include, but are not limited to:

- industry capacity
- imprecise reserves estimates of recoverable quantities of oil, natural gas and liquids from resource plays, and other sources not currently classified as reserves
- the effects of weather and climate conditions
- the results of exploration and development drilling, and related activities
- the ability of suppliers to meet commitments
- decisions or approvals from administrative tribunals
- risks associated with domestic and international oil and natural gas operations
- general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and natural gas prices
- refining and marketing margins
- the ability to produce and transport crude oil and natural gas to markets
- fluctuations in interest rates and foreign currency exchange rates
- actions by governmental authorities (including changes in taxes, royalty rates and resource-use strategies)
- changes in environmental and other regulations
- international political events
- nature and scope of actions by stakeholders and/or the general public

Many of these and other similar factors are beyond the control of Petro-Canada. Petro-Canada discusses these factors in greater detail in filings with the Canadian provincial securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC).

Readers are cautioned that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this quarterly report is made as of July 24, 2008 and, except as required by applicable law, will not be publicly updated or revised. This cautionary statement expressly qualifies the forward-looking information in this quarterly report.

Petro-Canada disclosure of reserves

Petro-Canada's qualified reserves evaluators prepare the reserves estimates the Company uses. The Canadian provincial securities commissions do not consider Petro-Canada's reserves staff and management as independent of the Company. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements that allows Petro-Canada to make disclosure in accordance with SEC standards where noted in this quarterly report. This exemption allows comparisons with U.S. and other international issuers.

As a result, Petro-Canada formally discloses its proved reserves data using U.S. requirements and practices, and these may differ from Canadian domestic standards and practices. The use of the terms such as "*probable*," "*possible*," "*resources*" and "*life-of-field production*" in this quarterly report does not meet the SEC guidelines for SEC filings. To disclose reserves in SEC filings, oil and gas companies must prove they are economically and legally producible under existing economic and operating conditions. Note that when the term barrel of oil equivalent (boe) is used in this quarterly report, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf) to one barrel (bbl) is based on an energy equivalency conversion method. This method primarily applies at the burner tip and does not represent a value equivalency at the wellhead.

The table below describes the industry definitions that Petro-Canada currently uses:

Definitions Petro-Canada uses	Reference
Proved oil and natural gas reserves (includes both proved developed and proved undeveloped)	SEC reserves definition (Accounting Rules Regulation S-X 210.4-10, U.S. Financial Accounting Standards Board (FASB) Statement No. 69) SEC Guide 7 for Oilsands Mining
Unproved reserves, probable and possible reserves	Canadian Securities Administrators: Canadian Oil and Gas Evaluation (COGE) Handbook, Vol. 1 Section 5 prepared by the Society of Petroleum Evaluation Engineers (SPEE) and the Canadian Institute of Mining Metallurgy and Petroleum (CIM)
Contingent and Prospective Resources	Petroleum Resources Management System: Society of Petroleum Engineers, SPEE, World Petroleum Congress and American Association of Petroleum Geologist definitions (approved March 2007) Canadian Securities Administrators: COGE Handbook Vol. 1 Section 5

Although the Society of Petroleum Engineers resource classification has categories of 1C, 2C, 3C for Contingent Resources, and low, best and high estimates for Prospective Resources, Petro-Canada will only refer to the 2C for Contingent Resources and the risked (an assessment of the probability of discovering the resources) best estimate for Prospective Resources, when referencing resources in this quarterly report. Canadian Oil Sands represents approximately 71% of Petro-Canada's total for Contingent and Prospective Resources. The balance of Petro-Canada's resources is spread out across the business, most notably in the North American frontier and International areas. Also, when Petro-Canada references resources for the Company, Contingent Resources are approximately 53% and risked Prospective Resources are approximately 47% of the Company's total resources.

Cautionary statement: In the case of discovered resources or a subcategory of discovered resources other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources. In the case of undiscovered resources or a subcategory of undiscovered resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

For movement of resources to reserve categories, all projects must have an economic depletion plan and may require

- additional delineation drilling and/or new technology for oil sands mining, *in situ* and conventional Contingent and risked Prospective Resources, prior to project sanction and regulatory approvals; and
- exploration success with respect to conventional risked Prospective Resources prior to project sanction and regulatory approvals.

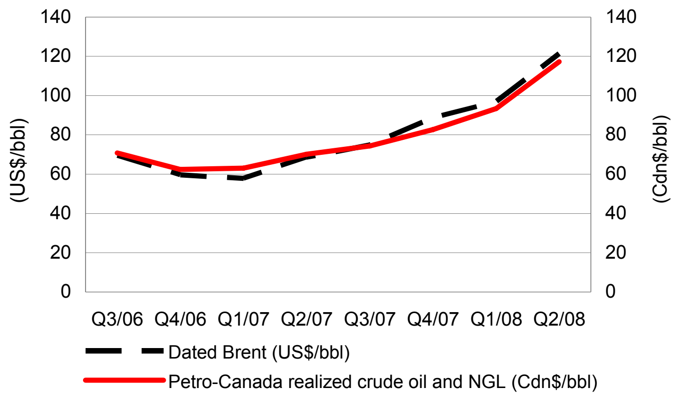
Reserves and resource information contained in this quarterly report is as at December 31, 2007.

BUSINESS ENVIRONMENT

Market prices shown below influence average prices realized for crude oil, natural gas liquids (NGL), natural gas and petroleum products in the table on page 22.

UPSTREAM

Crude Oil



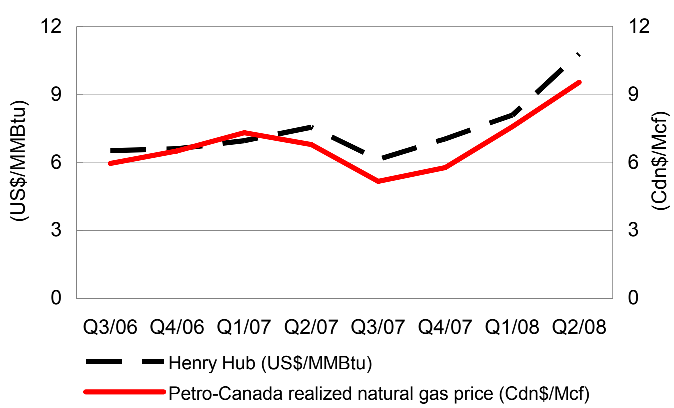
The price of Dated Brent averaged $121.38 US/bbl in the second quarter of 2008, up 77% compared with $68.76 US/bbl in the second quarter of 2007. Concern about global oil demand outpacing supply gains, combined with geopolitics and speculation, led to record high oil prices during the quarter.

During the second quarter of 2008, the Canadian dollar averaged $0.99 US, up from $0.91 US in the second quarter of 2007.

As a result, Petro-Canada's corporate-wide realized Canadian dollar prices for crude oil and NGL increased 67%, from $70.14/bbl in the second quarter of 2007 to $117.22/bbl in the second quarter of 2008.

In the second quarter of 2008, the spread between Dated Brent and Mexican Maya widened to $18.38 US/bbl, compared with $13.45 US/bbl in the second quarter of 2007. In Canada, the spread between Edmonton Light and Western Canada Select (WCS) widened to $23.20/bbl in the second quarter of 2008, compared with $22.12/bbl in the second quarter of 2007.

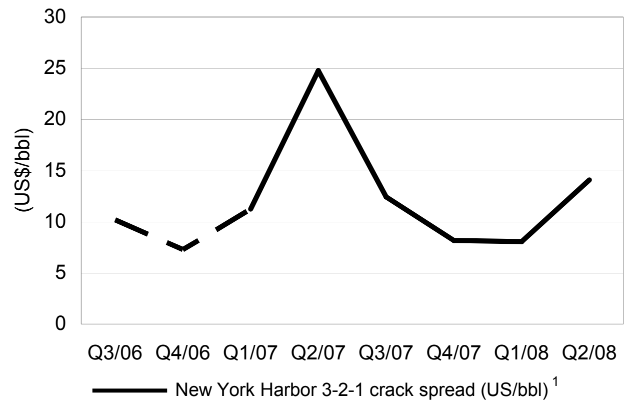
Natural Gas



North American natural gas prices at the Henry Hub were higher in the second quarter of 2008, compared with the second quarter of 2007, due to higher fuel oil prices and below average injections into storage. In the second quarter of 2008, NYMEX Henry Hub natural gas prices averaged $10.80 US/million British thermal units (MMBtu), up 43% from $7.56 US/MMBtu in the second quarter of 2007. The gain in Henry Hub natural gas prices was partially offset by the strong appreciation of the Canadian dollar, compared with the second quarter of 2007.

Petro-Canada's realized Canadian dollar prices for its North American Natural Gas business averaged $9.64/Mcf in the second quarter of 2008, up 40% from $6.87/Mcf in the second quarter of 2007.

DOWNSTREAM



New York Harbor 3-2-1 refinery crack spreads averaged $14.09 US/bbl in the second quarter of 2008, down 43% compared with an average of $24.76 US/bbl in the second quarter of 2007. Weaker gasoline spreads resulted from a combination of declining demand, ethanol penetration and increased refinery runs to capture higher diesel margins. Heating oil crack spreads remained strong, compared with the second quarter of 2007, due to global distillate demand, especially for diesel, continuing to increase.

1 On January 1, 2007, the New York Harbor 3-2-1 crack spread calculation changed. It is now based on Reformulated Gasoline Blendstock for Oxygenate Blending (RBOB) gasoline (the base for blending gasoline with 10% denatured ethanol) as opposed to conventional gasoline. Due to this change in specification, 2007 and 2008 crack spread values are not directly comparable to 2006 values.

The average market prices for the periods stated were:

	Three months ended June 30,		**Six months ended June 30,**	
	2008	2007	**2008**	2007
Dated Brent at Sullom Voe (*US$/bbl)*	**121.38**	68.76	**109.14**	63.26
West Texas Intermediate (WTI) at Cushing (*US$/bbl)*	**123.98**	65.03	**110.94**	61.60
Dated Brent/Maya FOB price differential *(US$/bbl)*	**18.38**	13.45	**17.08**	12.92
Edmonton Light (*Cdn$/bbl)*	**126.72**	72.24	**112.40**	70.01
Edmonton Light/WCS FOB price differential *(Cdn$/bbl)*	**23.20**	22.12	**22.40**	20.14
Natural gas at Henry Hub (*US$/MMBtu)*	**10.80**	7.56	**9.44**	7.26
Natural gas at AECO (*Cdn$/Mcf)*	**9.75**	7.69	**8.59**	7.73
New York Harbor 3-2-1 crack spread (*US$/bbl)*	**14.09**	24.76	**11.07**	18.01
Exchange rate (*US cents/Cdn$)*	**99.0**	91.1	**99.3**	88.1
Average realized prices				
Crude oil and NGL *($/barrel - $/bbl)*	**117.22**	70.14	**104.67**	66.73
Natural gas (*$/thousand cubic feet - $/Mcf)*	**9.55**	6.79	**8.56**	7.06

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2007 net earnings had these changes occurred. Amounts are in Canadian dollars unless otherwise specified.

Factor [1, 2]	Change (+)	Annual net earnings impact *(millions of dollars)*	Annual net earnings impact *($/share)* [3]
Upstream			
Price received for crude oil and NGL [4]	$1.00/bbl	$ 52	$ 0.11
Price received for natural gas	$0.25/Mcf	30	0.06
Exchange rate: US$/Cdn$ refers to impact on upstream earnings[5]	$0.01	(40)	(0.08)
Crude oil and NGL production	1,000 barrels/day (b/d)	10	0.02
Natural gas production	10 million cubic feet/day (MMcf/d)	7	0.01
Downstream			
New York Harbor 3-2-1 crack spread	$1.00 US/bbl	22	0.05
Chicago 3-2-1 crack spread	$1.00 US/bbl	24	0.05
Seattle 3-2-1 crack spread	$1.00 US/bbl	7	0.01
WTI/Dated Brent price differential	$1.00 US/bbl	25	0.05
Dated Brent/Maya FOB price differential	$1.00 US/bbl	6	0.01
Edmonton Light/Synthetic price differential	$1.00 Cdn/bbl	13	0.03
Exchange rate: US$/Cdn$ refers to impact on Downstream cracking margins and crude price differentials [6]	$0.01	(11)	(0.02)
Natural gas fuel cost – AECO natural gas price	$1.00 Cdn/Mcf	(11)	(0.02)
Asphalt - % of Maya crude oil price	1%	2	–
Heavy fuel oil (HFO) - % of WTI crude oil price	1%	2	–
Corporate			
Exchange rate: US$/Cdn$ refers to impact of the revaluation of U.S. dollar-denominated long-term debt [7]	$0.01	$ 10	$ 0.02

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.
2 The impact of these factors is illustrative.
3 Per share amounts are based on the number of shares outstanding as at December 31, 2007.
4 This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent, excluding the derivative contracts associated with the Buzzard acquisition that were closed out in the fourth quarter of 2007.
5 A strengthening Canadian dollar compared with the U.S. dollar has a negative effect on upstream net earnings.
6 A strengthening Canadian dollar compared with the U.S. dollar has a negative effect on Downstream cracking margins and crude price differentials.
7 A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings with respect to the Company's U.S. denominated debt. The impact refers to gains or losses on $1.4 billion US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on $1.1 billion US of the Company's U.S. denominated long-term debt, associated with the self-sustaining International business segment and the U.S. Rockies operations included in the North American Natural Gas business unit, are deferred and included as part of shareholders' equity.

BUSINESS STRATEGY

Petro-Canada's strategy is to create shareholder value by delivering long-term, profitable growth and improving the profitability of the base business.

Petro-Canada's capital program supports bringing on seven major projects over the next several years to deliver long-term profitable growth. For the remainder of 2008, the Company expects to complete the project to convert the Edmonton refinery to process lower cost, oil sands-based feedstock and commence startup, and to make final investment decisions (FID) on the Fort Hills mining and upgrading project, and Montreal coker project. The Company and its partners also plan to advance the following upstream projects: the MacKay River *in situ* expansion, the extension of the White Rose field off the East Coast of Canada, the Syria Ebla gas project and the developments associated with the new Libya Exploration and Production Sharing Agreements (EPSA). The Company anticipates upstream production will significantly increase as these big projects come on-stream. These projects are expected to add significant earnings and cash flow.

Petro-Canada continually works to strengthen its base business by improving the safety, reliability and efficiency of its operations. For the remainder of 2008, the Company is focused on delivering upstream production in line with guidance.

Strategic Priorities	Quarterly Progress
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• advanced construction of the Edmonton refinery conversion project (RCP), which was 92% complete at the end of the second quarter of 2008 and on track for startup in the fourth quarter of 2008 • mobilized the Syria Ebla gas engineering, procurement and construction (EPC) team • signed six new EPSAs with the Libya National Oil Company (NOC), adding reserves and extending terms by an expected 30 years with improved commercial terms
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• achieved 93% facility reliability at Terra Nova • maintained reliability at 99% for Western Canada natural gas processing facilities • operated MacKay River at 97% reliability • delivered a combined reliability index of 98 at all three Downstream production facilities • saw convenience store sales decline by 2% and same-store sales decline by 3%, compared with the second quarter of 2007
MAINTAINING FINANCIAL DISCIPLINE AND FLEXIBILITY	• ended the quarter with debt levels at 20.7% of total capital and a ratio of 0.8 times debt-to-cash flow from operating activities • accessed $1.5 billion US of debt securities through the Company's base shelf prospectus • renewed NCIB program for the repurchase of up to 5% of the Company's outstanding common shares from June 22, 2008 to June 21, 2009
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• experienced total recordable injury frequency (TRIF) of 0.75 in the first six months of 2008, an improvement from a TRIF of 0.87 for the full year in 2007 • updated our Code of Business Conduct to better reflect relevant business issues and provide better advice to employees and contractors • expanded the Total Loss Management audit program to incorporate a focus on process safety

STRATEGIC MILESTONES

Q3 2008

- expect to make FID on potential 25,000 b/d coker at Montreal refinery, subject to labour dispute resolution
- anticipate receipt of a regulatory decision on the Fort Hills mine plan amendment application
- anticipate conclusion of Hebron formal agreements

Q4 2008

- plan to complete Edmonton RCP project and commence startup
- anticipate receipt of a regulatory decision on the Fort Hills Sturgeon County Upgrader
- expect to make FID on the Fort Hills integrated mining and upgrading project

Q1 2009

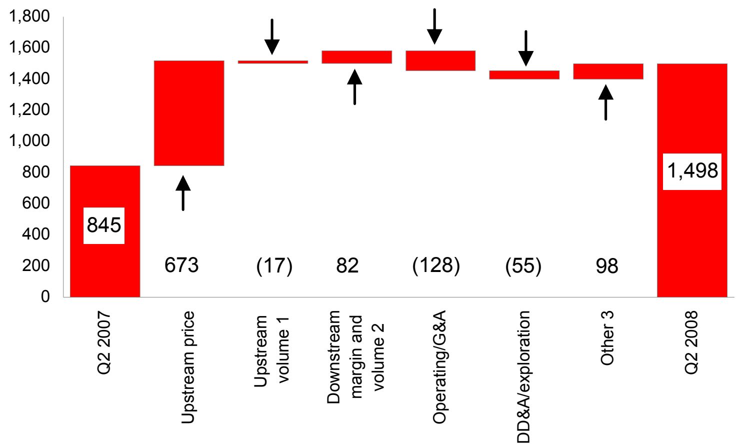
- expect to make FID on the MacKay River expansion project

ANALYSIS OF CONSOLIDATED EARNINGS

Earnings Variances

Q2/08 VERSUS Q2/07 FACTOR ANALYSIS

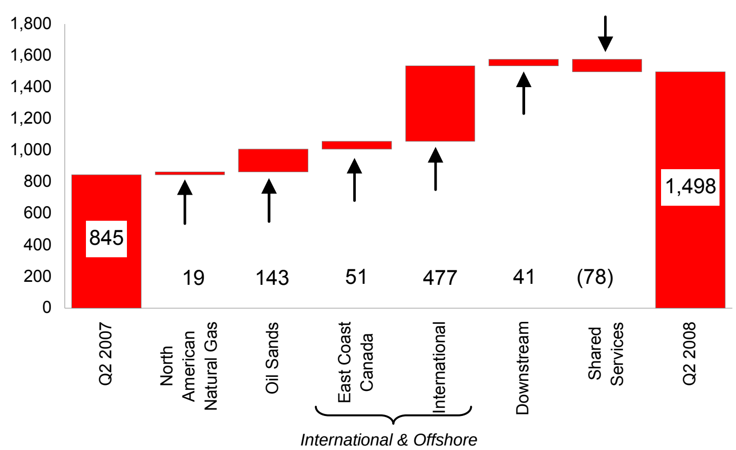
Net Earnings
(millions of Canadian dollars, after-tax)



Net earnings increased 77% to $1,498 million ($3.10/share) in the second quarter of 2008, compared with $845 million ($1.71/share) in the second quarter of 2007. Strong realized crude oil and natural gas prices, lower other[3] expenses and improved Downstream margin and volume[2] contributed to higher net earnings. These factors were partially offset by lower upstream production[1] and increased operating, general and administrative (G&A) and depreciation, depletion and amortization (DD&A) and exploration expenses.

1 Upstream volumes included the portion of DD&A expense associated with changes in upstream production levels.
2 Downstream margin and volume included the positive impact on realized margins from escalating crude oil feedstock costs while using a "first-in, first-out" (FIFO) inventory valuation methodology.
3 Other mainly included the change in fair value of the Buzzard derivative contracts (applies to 2007 and prior only), foreign currency translation, interest expense, changes in effective tax rates, gain on sale of assets, insurance proceeds and upstream inventory movements.

Net Earnings by Segment
(millions of Canadian dollars, after-tax)



The increase in second quarter net earnings on a segmented basis reflected higher North American Natural Gas, Oil Sands, East Coast Canada, International and Downstream net earnings. The results were partially offset by higher Shared Services costs.

During the second quarter of 2008, cash flow from operating activities was $2,479 million ($5.12/share), up 73% from $1,435 million ($2.91/share) in the same quarter of 2007. The increase in cash flow from operating activities primarily reflected higher net earnings.

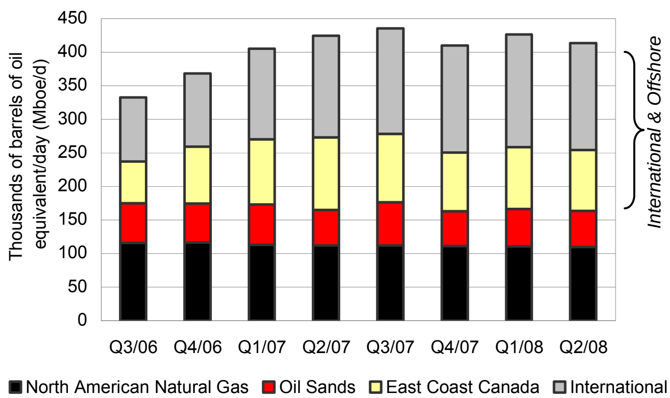
Quarterly Financial Information

	Three months ended							
(millions of Canadian dollars, except per share amounts)	**June 30 2008**	March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007	March 31 2007	Dec. 31 2006	Sept. 30 2006
Total revenue	**$ 7,646**	$ 6,586	$ 5,434	$ 5,497	$ 5,478	$ 4,841	$ 4,550	$ 5,201
Net earnings	**$ 1,498**	$ 1,076	$ 522	$ 776	$ 845	$ 590	$ 384	$ 678
Per share – basic	**3.10**	2.22	1.08	1.59	1.71	1.19	0.77	1.36
– diluted	**3.07**	2.20	1.07	1.58	1.70	1.18	0.76	1.34

UPSTREAM

Production

Petro-Canada converts volumes of natural gas to oil equivalent at a rate of six Mcf of natural gas to one bbl of oil. Production volumes disclosed refer to net working interest before royalties, unless otherwise specified.



In the second quarter of 2008, production averaged 414,000 barrels of oil equivalent per day (boe/d) net to Petro-Canada, down from 425,000 boe/d net in the same quarter of 2007. Lower volumes reflected decreased North American Natural Gas and East Coast Canada production, partially offset by increased Oil Sands and International production.

Exploration Update

In the first half of 2008, Petro-Canada and its partners finished operations on 10 of the up to 17 wells planned for the year. Three of the wells were completed as natural gas discoveries (Gubik-3 in the Alaska Foothills, Sancoche on Block 22 offshore Trinidad and Tobago, and van Ghent in the Netherlands sector of the North Sea). One appraisal well offshore Trinidad and Tobago (Cassra-2) confirmed Contingent Resources in the range of 0.6 trillion cubic feet (Tcf) to 1.3 Tcf in the earlier Cassra-1 discovery. Two wells were completed as non-commercial discoveries (Maria in the United Kingdom (U.K.) sector of the North Sea and L5a-11 in the Netherlands sector of the North Sea). Drilling of the Chandler-1 well in the Alaska Foothills was suspended, as planned, for re-entry next season. Three wells were dry and abandoned (Kwijika in the Northwest Territories, Gemini in the U.K. sector of the North Sea, and Tegu in Block 1a offshore Trinidad and Tobago).

2008 Consolidated Net Production Outlook

Upstream production is expected to be in the 400,000 boe/d to 420,000 boe/d range in 2008, slightly higher than the 390,000 boe/d to 420,000 boe/d range provided in the production outlook on December 13, 2007. The slight increase in expected volumes reflects increased North American Natural Gas, East Coast Canada and International production outlooks.

Factors that may impact production during the remainder of 2008 include reservoir performance, drilling results, facility reliability and successful execution of planned turnarounds.

(thousands of boe/d (Mboe/d) net)	**2008 Outlook (+/-)** *As at July 24, 2008*	**2008 Outlook (+/-)** *As at December 13, 2007*
North American Natural Gas		
– Natural gas	**94**	93
– Liquids	**12**	12
Oil Sands		
– Syncrude	**35**	35
– MacKay River	**25**	25
International & Offshore		
East Coast Canada	**87**	85
International		
– North Sea	**94**	93
– Other International	**58**	57
Total	**400 – 420**	390 – 420

North American Natural Gas

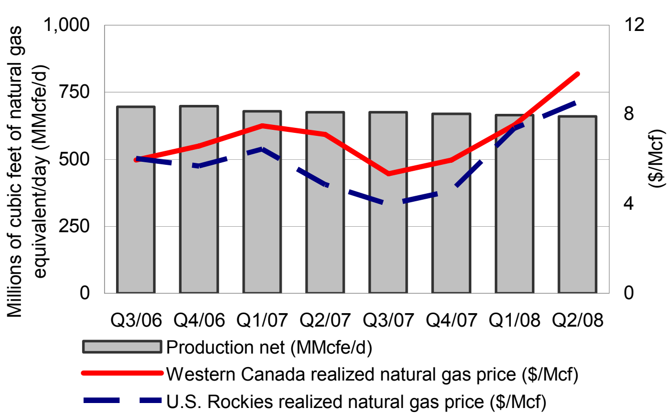
North American Natural Gas facilities continued to operate reliably in the second quarter of 2008, enabling the business to capture the value of higher natural gas, crude oil and sulphur prices.

(millions of Canadian dollars)	**Three months ended June 30, 2008**	Three months ended June 30, 2007	**Six months ended June 30, 2008**	Six months ended June 30, 2007
Net earnings	**$ 100**	$ 81	**$ 174**	$ 193
Cash flow from operating activities	**$ 379**	$ 247	**$ 578**	$ 406

North American Natural Gas recorded net earnings of $100 million in the second quarter of 2008, compared with net earnings of $81 million in the second quarter of 2007. Higher realized prices and lower exploration expenses were partially offset by a loss on sale of assets in the Minehead area of Western Canada, lower volumes and higher operating and DD&A expenses.

In the second quarter of 2008, the North American Natural Gas business recorded a net loss on sale of assets of $106 million. The main contributing factor was the sale of its Minehead assets in Western Canada for a loss on sale of $153 million before-tax ($112 million after-tax). The sale of these assets is aligned with the business unit's strategy to continuously optimize the assets in its portfolio.

North American Natural Gas Production and Pricing



In the second quarter of 2008, North American Natural Gas production declined by 2%, compared with the same period in 2007. Lower production reflected anticipated natural declines and scheduled turnarounds in Western Canada, largely offset by higher natural gas production in the U.S. Rockies.

Realized natural gas prices in Western Canada and the U.S. Rockies increased 38% and 76%, respectively, in the second quarter of 2008, compared with the same quarter of 2007, consistent with market price trends.

Production net *(MMcfe/d)* [1]		
Western Canada	**556**	598
U.S. Rockies	**104**	77
Total North American Natural Gas production net	**660**	675
Western Canada realized natural gas price *(Cdn$/Mcf)* [1]	**$9.82**	$7.11
U.S. Rockies realized natural gas price *(Cdn$/Mcf)* [1]	**$8.55**	$4.86

1 For North American Natural Gas crude oil and NGL production and average realized prices, refer to the charts on pages 21 and 22, respectively.

Petro-Canada operated gas plants and facilities in Western Canada delivered 99% reliability in the second quarter of 2008.

Scheduled Turnarounds

No major turnarounds are planned for the remainder of 2008.

Oil Sands

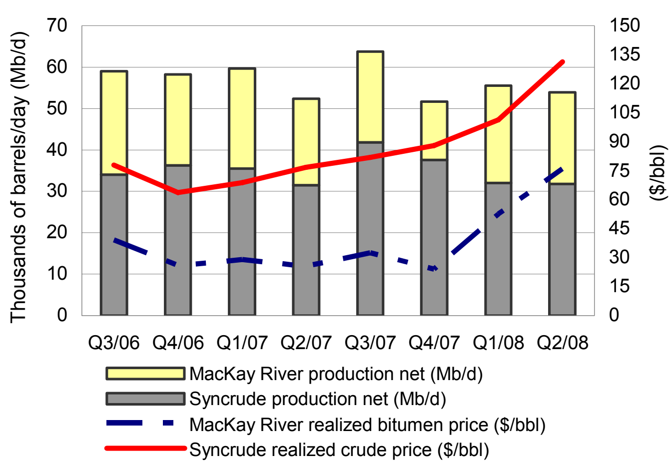
Financial results remained strong due to high realized crude and bitumen prices.

	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	**2008**	2007	**2008**	2007
Net earnings [1]	**$ 177**	$ 34	**$ 289**	$ 77
Cash flow from operating activities	**$ 162**	$ 160	**$ 328**	$ 229

1 Oil Sands bitumen inventory movements increased net earnings by $18 million before-tax ($12 million after-tax) and $21 million before-tax ($14 million after-tax) for the three and six months ended June 30, 2008, respectively. The same factor increased net earnings by $1 million before-tax ($1 million after-tax) and $4 million before-tax ($3 million after-tax) for the three and six months ended June 30, 2007, respectively.

In the second quarter of 2008, Oil Sands net earnings were $177 million, up from $34 million in the second quarter of 2007. Higher realized prices and production, and lower exploration and DD&A expenses were partially offset by higher operating costs.

Oil Sands Production and Pricing



Syncrude production was up 1% in the second quarter of 2008, compared with the second quarter of 2007. In the second quarter of 2008, there were reliability issues with the sulphur plants and a planned 45-day turnaround of Coker 8-1 was completed. Production in the second quarter of 2007 was reduced by a turnaround of Coker 8-3. Syncrude realized prices were 71% higher in the second quarter of 2008, compared with the second quarter of 2007.

MacKay River production was up 6% in the second quarter of 2008, compared with the same period of 2007, due to increased reliability, partially offset by planned preventative maintenance. MacKay River realized bitumen prices increased 197% in the second quarter of 2008, compared with the second quarter of 2007, due to higher WTI prices.

	Second Quarter 2008	Second Quarter 2007
Production net *(b/d)*		
Syncrude	**31,800**	31,500
MacKay River	**22,100**	20,900
Total Oil Sands production net	**53,900**	52,400
Syncrude realized crude price *($/bbl)*	**$131.37**	$76.71
MacKay River realized bitumen price *($/bbl)*	**$75.85**	$25.58

The planned 45-day turnaround of Coker 8-1 at Syncrude was executed largely on plan and to schedule. Syncrude experienced operational issues at two sulphur plants during the second quarter of 2008. The issues were largely resolved in May 2008. However, the plan is to have one of the sulphur plants shut down for repairs in July with minimal impact to production.

In the second quarter of 2008, MacKay River production reflected planned preventative maintenance that took place in May 2008. The plant made a strong return from the May 2008 turnaround and production averaged 26,400 b/d in June 2008. Operations at MacKay River continued to be strong, with reliability averaging 97% for the second quarter of 2008. As a result of improving reliability, MacKay River achieved both daily (28,400 b/d) and monthly (27,000 b/d) production records in April 2008.

Fort Hills Project

The first phase of the Fort Hills project is planned to produce 140,000 b/d gross of synthetic crude oil (84,000 b/d net). Associated bitumen production is expected to be about 160,000 b/d gross (96,000 b/d net). First bitumen production is expected to begin in the fourth quarter of 2011, with first synthetic crude oil production from the Sturgeon Upgrader anticipated in the second quarter of 2012. The preliminary capital cost estimate for the mine and upgrading components of the first phase of Fort Hills is $14.1 billion gross ($8.5 billion net). The project is currently in the front-end engineering and design (FEED) stage. FEED is expected to be completed in the third quarter of 2008, producing a definitive cost estimate and the basis upon which the FID on the project will be made during the fourth quarter of 2008.

Petro-Canada and its partners in the Fort Hills project have ordered long-lead items, such as coke drums, fractionating columns, reactors, crushers and breakers, cable shovels and 400-tonne haul trucks. The regulatory hearing for the Sturgeon Upgrader was completed in early July 2008 and a decision is expected in the fourth quarter of 2008. The partnership anticipates receiving a regulatory decision on an amendment to the approved mine plan, which incorporates improvements identified through the mine plan optimization process, in the third quarter of 2008.

On March 10, 2008, the federal government issued an update on the regulatory framework for industrial greenhouse gas (GHG) emissions. The federal government expects to develop and implement regulations over the next 18 months. The Company continues to examine these developments to determine their potential effects on the Company's operations and financial performance.

MacKay River Expansion Project

In the first quarter of 2008, the Company received regulatory approval for the proposed MacKay River 40,000 b/d *in situ* expansion project. Petro-Canada continues to refine the design for the project, to evaluate opportunities for integration with the Fort Hills project and to pursue cost-saving opportunities associated with using international engineering, procurement and construction contractors. FID is expected in the first quarter of 2009.

Scheduled Turnarounds

Syncrude is expected to begin its planned 45-day Coker 8-2 turnaround in the third quarter of 2008. There are no major turnarounds planned at MacKay River for the remainder of 2008.

Other Developments

Petro-Canada and its partners in Syncrude remain in negotiations with the Government of Alberta regarding the province's desire for Syncrude to move to the New Alberta Royalty Framework in advance of the expiry of Syncrude's existing royalty agreement in 2016.

International & Offshore

East Coast Canada

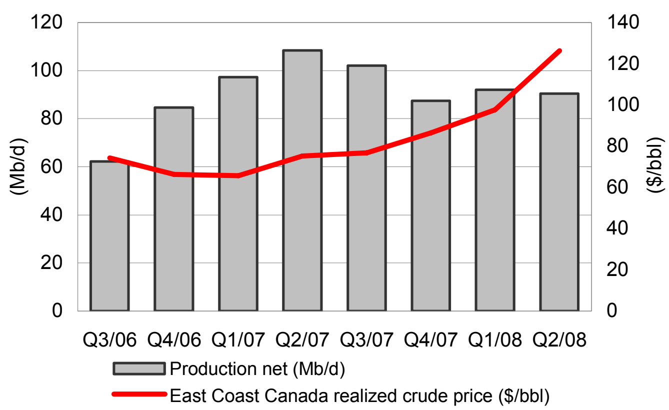
The business advanced the White Rose Extensions project with completion of FEED for the North Amethyst portion and commencement of the detailed design.

(millions of Canadian dollars)	Three months ended June 30, **2008**	2007	Six months ended June 30, **2008**	2007
Net earnings [1]	**$ 385**	$ 334	**$ 760**	$ 590
Cash flow from operating activities	**$ 670**	$ 346	**$ 1,155**	$ 827

1 East Coast Canada crude oil inventory movements decreased net earnings by $57 million before-tax ($39 million after-tax) and $63 million before-tax ($43 million after-tax) for the three and six months ended June 30, 2008, respectively. The same factor increased net earnings by $2 million before-tax ($1 million after-tax) and $25 million before-tax ($17 million after-tax) for the three and six months ended June 30, 2007, respectively.

Net earnings for East Coast Canada were $385 million in the second quarter of 2008, up from $334 million in the second quarter of 2007. Higher realized prices and lower operating, DD&A and exploration expenses were partially offset by lower production and higher royalty payments.

East Coast Canada Production and Pricing



In the second quarter of 2008, East Coast Canada production decreased 17%, compared with the same period in 2007. Terra Nova's production was lower due to bringing forward its planned 16-day turnaround from July to June 2008. Hibernia production was lower due to natural declines, partially offset by the positive impact of recent well workovers and strong reliability. White Rose volumes were lower due to the impact of unplanned shutdowns as a result of ice conditions at the beginning of the second quarter of 2008.

During the second quarter of 2008, East Coast Canada realized crude prices increased 68%, compared with the second quarter of 2007.

	Second Quarter 2008	Second Quarter 2007
Production net *(b/d)*		
Terra Nova	**34,900**	41,200
Hibernia	**27,100**	33,100
White Rose	**28,400**	34,100
Total East Coast Canada production net	**90,400**	108,400
Average realized crude price *($/bbl)*	**$126.35**	$75.29

The Terra Nova Floating Production, Storage and Offloading (FPSO) vessel operated at 93% facility reliability in the second quarter of 2008. The turnaround in the second quarter of 2008 to undertake planned maintenance and regulatory inspections was completed approximately two days ahead of schedule and on budget. Performance of the Terra Nova FPSO swivel was unchanged in the second quarter of 2008. All equipment and materials are in place to repair the swivel, if necessary, and further equipment and materials will be in place shortly for a replacement option.

Scheduled Turnarounds

No major turnarounds are planned for the remainder of 2008.

White Rose Extensions Development

Early in the second quarter of 2008, the partners received regulatory approval for the North Amethyst development, and the Company approved the project to proceed. FEED for the North Amethyst portion of the project is complete and detailed design is underway. North Amethyst drilling is expected to begin in the third quarter of 2008. North Amethyst is the first of three extensions to the original White Rose field, with first oil from North Amethyst expected in late 2009 or early 2010.

East Coast Canada Royalties

In the second quarter of 2008, East Coast Canada royalties averaged 26% of gross revenue, compared with 12% in the second quarter of 2007. Terra Nova production was subject to Tier I royalties of 30% of net revenue and a Tier II royalty of an incremental 12.5% of net revenue, which was triggered during the second quarter of 2008. White Rose production was subject to a Tier I royalty of 20% of net revenue and a Tier II royalty of an incremental 10% of net revenue, which was triggered during the first quarter of 2008. Production from Hibernia continued to be subject to basic royalties of 5% of gross revenue.

International

The business had a strong financial quarter due to higher production and realized prices. Successfully completed ratification of the Libya EPSAs, unlocking a long life asset with material earnings and cash flow.

	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	**2008**	2007	**2008**	2007
Net earnings [1, 2]	**$ 672**	$ 195	**$ 1,008**	$ 204
Cash flow from operating activities	**$ 1,031**	$ 356	**$ 1,537**	$ 633

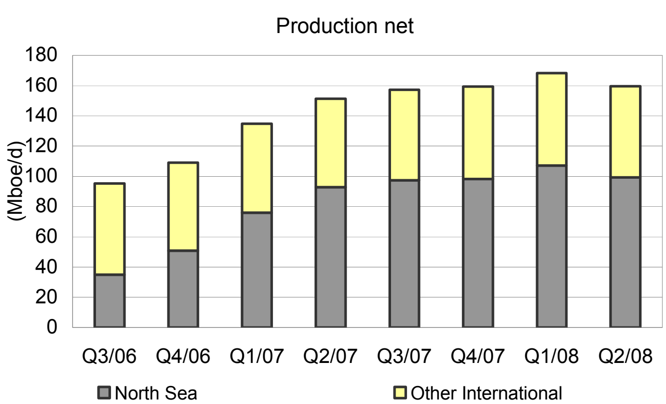
1 International crude oil inventory movements increased (decreased) net earnings by $42 million before-tax ($(14) million after-tax) and by $76 million before-tax ($11 million after-tax) for the three and six months ended June 30, 2008, respectively. The same factor increased (decreased) net earnings by $15 million before-tax ($21 million after-tax) and $(30) million before-tax ($(7) million after-tax) for the three and six months ended June 30, 2007, respectively.

2 During the fourth quarter of 2007, the Company entered into derivative contracts to close out the hedged portion of its Buzzard production from January 1, 2008 to December 31, 2010.

In the second quarter of 2008, International delivered net earnings of $672 million, compared with $195 million in the second quarter of 2007. The increase in net earnings was due to higher realized prices, increased production volumes, and lower operating and DD&A expenses. Lower operating and DD&A expenses were primarily due to the Libya EPSA ratification adjustment, partially offset by increased production from the North Sea. Other factors increasing net earnings were an incremental earnings adjustment and a future income tax recovery due to the ratification of the Libya EPSAs and the benefit associated with settling the Buzzard derivative contracts in the fourth quarter of 2007. These factors were partially offset by increased exploration expense due to well write-offs in the Netherlands, Syria, and Trinidad and Tobago.

Net earnings in the second quarter of 2008 included a $230 million future income tax recovery due to the ratification of the Libya EPSAs, a $47 million Libya EPSA incremental ratification adjustment and a $6 million gain on sale of mature assets in the Netherlands. The $47 million Libya EPSA incremental ratification adjustment was recorded to recognize incremental earnings on the new EPSAs relating to the period January 1 to March 31, 2008, which could not be recognized until ratification on June 19, 2008. Net earnings for the three and six months ended June 30, 2008 did not include amortization or interest expenses on the $1 billion US signing bonus, which could not be recognized until EPSA ratification. Net earnings in the second quarter of 2007 included a $30 million future income tax recovery and a $28 million unrealized loss on the Buzzard derivative contracts.

International Production and Pricing



International production increased 5% in the second quarter of 2008, compared with the second quarter of 2007.

In the second quarter of 2008, production from the North Sea increased by 7%, reflecting higher production from Buzzard. These additions were partially offset by anticipated natural declines in other North Sea assets. Other International production increased 3% in the second quarter of 2008, compared with the second quarter of 2007.

	Second Quarter 2008	Second Quarter 2007
Production net *(boe/d)*		
U.K. sector of the North Sea	**78,700**	68,600
The Netherlands sector of the North Sea	**20,700**	24,200
North Sea	**99,400**	92,800
Other International	**60,100**	58,400
Total International production net	**159,500**	151,200
Average realized crude oil and NGL prices *($/bbl)*	**$114.33**	$72.04
Average realized natural gas price *($/Mcf)*	**$9.05**	$6.27

International operations' realized crude oil and NGL prices increased 59% in the second quarter of 2008, compared with the same period in 2007. Realized prices for natural gas increased 44% in the second quarter of 2008, compared with the same period in the prior year.

North Sea

Buzzard production averaged approximately 200,200 boe/d gross (59,900 boe/d net) from 11 production wells in the second quarter of 2008, up compared with the same quarter of 2007. The Frigg transportation system, which transports Buzzard's natural gas production to market, completed a planned maintenance shutdown in early July 2008. During this period of reduced pipeline availability the Buzzard drilling jack-up rig was demobilized from the platform for planned maintenance and recertification. Buzzard is expected to commence a further planned turnaround in August for the reinstallation of the jack-up rig. Work on detailed engineering and ordering of long-lead items for the fourth platform is underway to treat higher than expected hydrogen sulphide content in some Buzzard wells.

In the Netherlands sector of the North Sea, the Petro-Canada operated De Ruyter facility continued to perform well, delivering 19,300 boe/d gross (10,400 boe/d net) of production in the second quarter of 2008.

The Company signed a sales and purchase agreement on May 31, 2008 with Bayerngas Norge AS for the sale of all of the Company's interests in Denmark for proceeds of $120 million US plus closing adjustments. The deal is subject to Danish government approval and is expected to close in the third quarter of 2008. The sale of all of Petro-Canada's interests in Denmark is consistent with the International business unit strategy to optimize the International portfolio by reducing participation in countries where the Company cannot develop a material position.

Other International

Production in Libya averaged 49,600 boe/d in the second quarter of 2008, up from 46,200 boe/d in the same quarter of 2007 due to improved production performance at the En Naga and Ghani fields.

Trinidad and Tobago offshore gas production averaged 63 MMcf/d in the second quarter of 2008, down compared with 73 MMcf/d in the second quarter of 2007. The decrease was due to reduced deliveries as a result of scheduled and unscheduled turnarounds in the second quarter of 2008.

Syria Ebla Gas Project

In the second quarter of 2008, Petro-Canada mobilized the EPC team and continued to advance the project. When completed, the Ebla gas project is expected to produce 80 MMcf/d of natural gas, with first gas anticipated in 2010.

Libya Concession Development

In June 2008, Petro-Canada signed six new EPSAs with the Libya NOC to replace existing concession agreements and one EPSA. The new EPSAs were ratified as of the signing with an effective date of January 1, 2008. The commercial terms of the new agreements, including the signing bonus, match those announced when the heads of agreement were completed in December 2007. Under the new agreements, Petro-Canada will pay 50% of all development capital and will initially receive a 12% entitlement[1] share of production. The Company will continue to report production on a before-royalty working interest basis. The Company estimates that there are gross Contingent and Prospective Resources[2] of almost two billion barrels of oil associated with the redevelopment program. Following ratification of the new agreements, a payment of $500 million US, representing 50% of the signature bonus, was made to the Libya NOC in July 2008 with the remainder to be paid between 2009 and 2013.

The agreements will enable Petro-Canada to design and implement jointly with the NOC the redevelopment of major fields. Petro-Canada's Libya concessions currently produce approximately 100,000 b/d gross (50,000 b/d net) on an

[1] Entitlement refers to Petro-Canada's share of production after royalties and local taxes.
[2] The resource number quoted does not include reserves and is approximately 75% Contingent Resources and 25% Risked Prospective Resources.

annual average basis. Under the new agreements, production from the redevelopment program is expected to double over the next five to seven years.

The Company also proposes to invest $460 million US over the next seven years on a 100%-operated exploration program in the Sirte region, one of the world's most prolific basins. Success from this exploration program could materially add to reserves and production.

Scheduled Turnarounds

Buzzard is expected to commence its planned maintenance turnarounds for a total of nine-days in the third quarter of 2008.

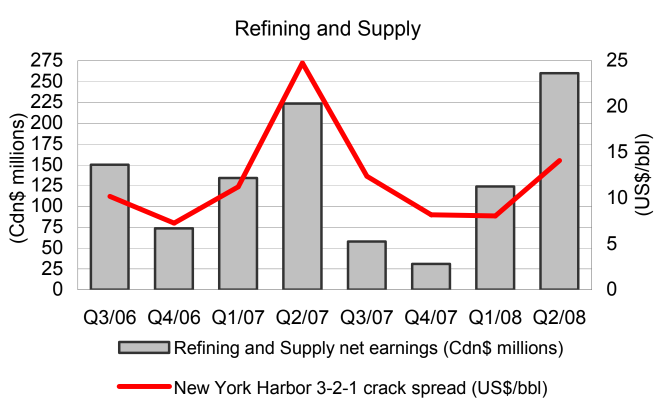
DOWNSTREAM

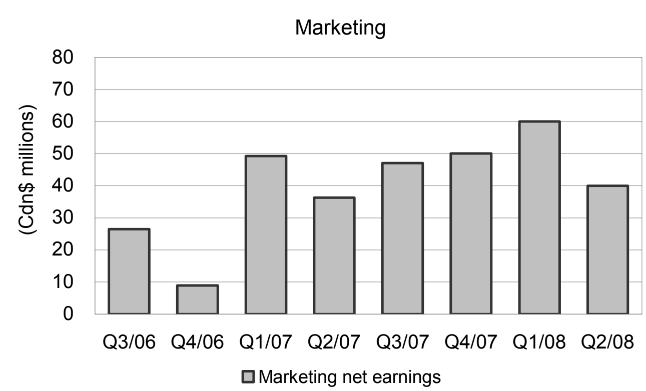
The Downstream delivered reliable operations, while managing through a weaker business environment in the second quarter of 2008.

(millions of Canadian dollars)	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Net earnings	**$ 300**	$ 259	**$ 484**	$ 443
Cash flow from operating activities	**$ 41**	$ 320	**$ 25**	$ 534

The Downstream business recorded net earnings of $300 million in the second quarter of 2008, up from $259 million in the same quarter of 2007. The increased net earnings reflected the positive impact from escalating crude oil feedstock costs while using a FIFO inventory valuation methodology, favourable crude price differentials, lower costs for other feedstock and higher distillate cracking margins. These factors were partially offset by lower gasoline cracking margins, a decrease in realized refining margins for asphalt and heavy fuel oil, light oil, lubricants, liquid petroleum gases and petrochemical products, lower refinery yields and increased operating costs.

Downstream Net Earnings





	Second Quarter 2008	Second Quarter 2007
Refining and Supply net earnings *(millions of Canadian dollars)*	**$260**	$223
New York Harbor 3-2-1 crack spread *(US$/bbl)*	**$14.09**	$24.76
Chicago 3-2-1 crack spread *(US$/bbl)*	**$12.91**	$29.17
Seattle 3-2-1 crack spread *(US$/bbl)*	**$16.47**	$32.72
Marketing net earnings *(millions of Canadian dollars)*	**$40**	$36

The average New York Harbor 3-2-1 refinery crack spread was $14.09 US/bbl in the second quarter of 2008, down from $24.76 US/bbl in the second quarter of 2007. The average international light/heavy crude price differential was $18.38 US/bbl in the second quarter of 2008, compared with $13.45 US/bbl in the second quarter of 2007.

In the second quarter of 2008, total sales of refined petroleum products were relatively flat at 4.7 billion litres, compared with the same period last year. Higher Refining and Supply and lubricants sales volumes were offset by lower Marketing sales volumes due to overall weaker demand.

Refining and Supply contributed second quarter 2008 net earnings of $260 million, up from $223 million in the same quarter of 2007. Results reflected the following three items. First, net earnings were positively impacted from escalating crude oil feedstock costs while using FIFO inventory valuation methodology. Second, net earnings were impacted by favourable crude price differentials and lower costs for other feedstock. Third, net earnings were impacted by higher distillate cracking margins. These factors were partially offset by the following four key items. First, net earnings were negatively impacted by lower gasoline cracking margins. Second, net earnings were impacted by lower realized refining margins for asphalt and heavy fuel oil, light oil, lubricants, liquid petroleum gases and petrochemical products. Third, net earnings were impacted by lower refinery yields associated with crude availability and quality issues at Edmonton, and planned turnaround activity and partial unit shutdown at Montreal. Fourth, net earnings were impacted by increased operating expenses primarily associated with environmental costs for the Quebec green levy and Alberta GHG legislation, and turnaround costs at Montreal.

Marketing contributed second quarter 2008 net earnings of $40 million, up compared with $36 million in the same quarter of 2007. In the second quarter of 2008, Marketing results reflected the positive impact to the lubricants business from escalating crude oil feedstock costs while using FIFO inventory valuation methodology. This factor was partially offset by increased operating expenses due to higher fuel costs associated with delivery and card fees.

Downstream Turnaround Activity

In August 2008, the Edmonton refinery is expected to begin its planned two-month turnaround to tie-in the RCP and to complete routine maintenance on other units within the refinery. Increased expenses are expected to be about $20 million after-tax. Parts of the refinery will continue to operate under modified operations to limit the shortfall in light oil production. It is anticipated that production through this planned turnaround will be approximately 30% of normal levels. This means that the refining margin will be maintained on that volume, while the marketing margin will be retained on all sales volumes. The Company intends to mitigate the impact of lost production on customers by entering time trades and purchasing additional finished product.

Edmonton Refinery Conversion Project

At the Edmonton refinery, the Company is investing to convert the facility to run oil sands-based feedstock. The RCP will enable Petro-Canada to directly upgrade up to 26,000 b/d of bitumen and process up to 48,000 b/d of sour synthetic crude oil, replacing the more expensive conventional light crude feedstock currently refined.

At the end of the second quarter of 2008, Petro-Canada had completed 92% of the construction and the project is now entering the ramp down phase. The Edmonton RCP cost estimate has increased from $2.2 billion to $2.5 billion as a result of additional work and rework combined with lower than expected labour productivity. Approximately 93% of the revised estimated project costs were committed as at June 30, 2008. The project is anticipated to start up in the fourth quarter of 2008.

Change in Accounting for Inventory and Crude Oil and Product Purchases

On January 1, 2008, Petro-Canada adopted the FIFO method for valuing its crude oil and refined product inventories. The change is due to the "last-in, first-out" (LIFO) method no longer being permitted under Canadian generally accepted accounting principles (GAAP). As a result of changing from the LIFO inventory costing method to FIFO, a one-time adjustment to increase inventories by $812 million, future income tax liabilities by $256 million and retained earnings by $556 million was recorded. This adjustment occurred on January 1, 2008 and increased the Company's working capital and Downstream capital employed values. A second impact relates to reported cost of crude oil and product purchases. The change in methodology reflects historic crude oil prices at the time the crude oil is purchased. Reported operating revenues continue to reflect current market prices when the crude oil is refined and sold. As a result of the lag between when crude oil is purchased and when product is sold, and fluctuating crude oil prices, future reported Downstream earnings may be more volatile.

CORPORATE

Shared Services and Eliminations *(millions of Canadian dollars)*	**Three months ended** **2008**	2007	**Six months ended** **2008**	2007
Net loss	**$ (136)**	$ (58)	**$ (141)**	$ (72)
Cash flow from (used in) operating activities	**$ 196**	$ 6	**$ 291**	$ (28)

Shared Services and Eliminations recorded a net loss of $136 million in the second quarter of 2008, compared with a net loss of $58 million for the same period in 2007. The net loss in the second quarter of 2008 included a $117 million charge related to the mark-to-market valuation of stock-based compensation and a $13 million foreign currency translation loss on long-term debt, partially offset by foreign exchange gains on U.S. dollar cash balances held during the second quarter of

2008. The net loss in the second quarter of 2007 included a $97 million charge related to the mark-to-market valuation of stock-based compensation and a $104 million foreign currency translation gain on long-term debt.

Interest expense was $47 million before-tax during the second quarter of 2008, up from $41 million in the second quarter of the prior year. The Company capitalized $15 million of interest expense during the quarter, compared with $7 million in the second quarter of 2007.

Cash flow from operating activities was affected by tax deferrals, resulting from the Company's upstream partnership. These deferrals increased cash flow from operating activities by about $72 million in the quarter, compared with a decrease of $13 million in the same period last year. On January 1, 2008, the Company adopted the FIFO costing method for valuing its Downstream inventories, which is consistent with the method prescribed for income tax purposes, thereby eliminating the difference in earnings and cash flow from operating activities.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	**2008**	2007	**2008**	2007
Cash flow from operating activities	**$ 2,479**	$ 1,435	**$ 3,914**	$ 2,601
Net cash (outflows) inflows from:				
Investing activities	**(1,201)**	(863)	**(2,171)**	(1,573)
Financing activities	**701**	(475)	**267**	(623)
Increase in cash and cash equivalents	**1,979**	97	**2,010**	405
Cash and cash equivalents	**$ 2,241**	$ 904	**$ 2,241**	$ 904

Petro-Canada's financing strategy is designed to maintain financial strength and flexibility to support profitable growth in all business environments. Two key measures that Petro-Canada uses to measure the Company's overall financial strength are debt-to-cash flow from operating activities and debt-to-debt plus equity. Petro-Canada's debt-to-cash flow from operating activities ratio, a key short-term leverage measure, was 0.8 times at June 30, 2008. This was within the Company's target range of no more than 2.0 times. Debt-to-debt plus equity, the long-term measure for capital structure, was 20.7% at June 30, 2008, below the Company's target range of 25% to 35%.

Financial Ratios	**June 30, 2008**	December 31, 2007	June 30, 2007
Debt-to-cash flow from operating activities *(times)* [1]	**0.8**	1.0	0.6
Debt-to-debt plus equity *(%)*	**20.7**	22.5	18.6

1 Calculated on a 12-month rolling basis.

Operating Activities

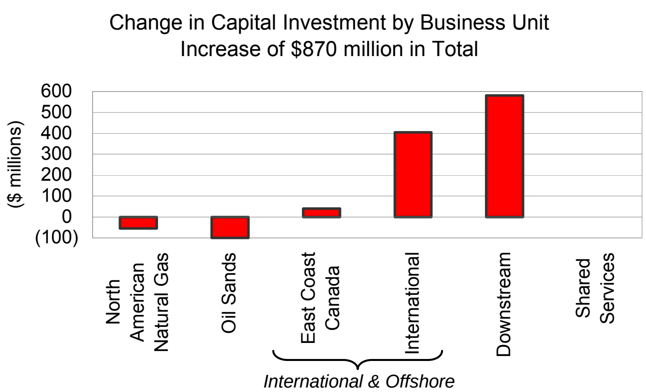
Excluding cash and cash equivalents, the current portion of long-term debt and short-term notes payable, the operating working capital deficiency was $275 million at the end of the second quarter of 2008, compared with an operating working capital deficiency of $565 million at December 31, 2007.

Investing Activities

(millions of Canadian dollars)	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Upstream				
North American Natural Gas	**$ 91**	$ 116	**$ 258**	$ 321
Oil Sands	**225**	106	**403**	196
International & Offshore				
East Coast Canada	**44**	48	**82**	86
International	**1,269**	172	**1,520**	329
	1,629	442	**2,263**	932
Downstream				
Refining and Supply	**467**	292	**819**	497
Sales and Marketing	**32**	22	**55**	36
Lubricants	**4**	5	**7**	7
	503	319	**881**	540
Shared Services	**9**	7	**13**	12
Total property, plant and equipment and exploration	**2,141**	768	**3,157**	1,484
Other assets	**–**	15	**–**	32
Total	**$ 2,141**	$ 783	**$ 3,157**	$ 1,516

Outlook – Capital Expenditures

Capital expenditures in 2008 are expected to be $6,155 million, up from the December 13, 2007 outlook of $5,285 million.



Capital investment in 2008 is expected to increase by $870 million, compared with previous guidance. Capital investment in the Downstream is expected to increase by $580 million, mainly due to revised cost estimates associated with the Edmonton RCP as a result of increased work and rework combined with lower than expected labour productivity. This brings the total cost estimate for RCP from $2.2 billion to $2.5 billion. Capital investment in International is expected to increase by $405 million, reflecting the accrual for the full impact of the $1 billion US signing bonus for the Libya EPSA ratification. About half of this amount was paid in 2008, with the remainder to be paid from 2009 to 2013. These factors were partially offset by lower upstream capital spending.

Capital Investment by Business Unit *(millions of Canadian dollars)*	**2008 Outlook** *As at July 24, 2008*	**2008 Outlook** *As at December 13, 2007*
Upstream		
North American Natural Gas	**$ 620**	$ 675
Oil Sands	**1,420**	1,520
International & Offshore		
East Coast Canada	**335**	295
International	**2,040**	1,635
	4,415	4,125
Downstream		
Refining and Supply	**1,520**	950
Sales and Marketing	**160**	150
Lubricants	**25**	25
	1,705	1,125
Shared Services	**35**	35
Total	**$ 6,155**	$ 5,285

Financing Activities

At the end of the second quarter of 2008, the Company's syndicated committed credit facilities and bilateral demand facilities totalled $3,570 million and $766 million, respectively, of which $285 million was used for letters of credit and overdraft coverage. The syndicated facilities also may be used to provide liquidity support to a commercial paper program. No commercial paper was outstanding at June 30, 2008.

During the second quarter of 2008, the Company issued $600 million US of 10-year notes and $900 million US of 30-year notes under its previously filed base shelf prospectus. The base shelf prospectus provides for the offering of up to $4 billion US of debt securities in Canada or the U.S. over the course of a 25-month period from the date of issue, March 31, 2008.

The Company's unsecured long-term debt ratings, which remain unchanged from year-end 2007, are Baa2 by Moody's Investors Service, BBB by Standard & Poor's and A (low) by Dominion Bond Rating Service.

For 2008 and beyond, spending on future large projects may result in annual capital expenditures exceeding operating cash flow. The Company anticipates that additional funding requirements will be met by external financing and that additional financial leverage can be managed in the context of Petro-Canada's target ranges.

Returning Cash to Shareholders

Petro-Canada's priority uses of cash are to fund the capital program and profitable growth opportunities, and to return cash to shareholders through dividends and a share buyback program. Petro-Canada renewed its NCIB program for the repurchase of its common shares from June 22, 2008 to June 21, 2009, entitling the Company to purchase up to 5% of its outstanding common shares, subject to certain conditions.

Petro-Canada regularly reviews its dividend strategy to ensure the alignment of its dividend policy with shareholder expectations, and financial and growth objectives. Consistent with this objective, on July 23, 2008, the Company declared a 54% increase in its quarterly dividend to $0.20/share, commencing with the dividend payable on October 1, 2008.

In the second quarter of 2008, the Company did not repurchase any of its shares, compared with 8.0 million in the same period last year. Future share repurchases will depend on excess cash available after consideration of the Company's priority uses of cash.

	Shares Repurchased		**Average Price**		**Total Cost** (*$ millions*)	
Period	**2008**	2007	**2008**	2007	**2008**	2007
First quarter	–	2,000,000	**$** –	$ 43.63	**$** –	$ 87
Second quarter	–	8,000,000	**$** –	$ 53.44	**$** –	$ 428
Year-to-date	–	10,000,000	**$** –	$ 51.48	**$** –	$ 515

Contingent Liabilities and Contractual Obligations

Contractual obligations are summarized in the Company's 2007 annual MD&A and contingent liabilities are disclosed in Note 24 of the 2007 annual Consolidated Financial Statements. Total contractual obligations at June 30, 2008 were $39.4 billion. During the second quarter of 2008, contractual obligations increased by $7.1 billion due to the $1.5 billion US debt issuance, new obligations resulting from the ratification of the Libya EPSAs and increased product purchases in the Downstream.

The Company has certain retail licensee agreements that qualify as variable interest entities, as described in Note 25 to the 2007 annual Consolidated Financial Statements. These entities were not consolidated as Petro-Canada is not the primary beneficiary and the Company's maximum exposure to losses from these arrangements was not expected to be material.

RISK

As at June 30, 2008, there were no material changes in the Company's risks or risk management activities since December 31, 2007. Petro-Canada's risk management activities are conducted in accordance with the policies and guidelines established by the Board of Directors. Readers should refer to Petro-Canada's 2007 AIF and the risk management section of the 2007 annual MD&A for further discussion of risks relating to Petro-Canada's business.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2006, Canada's Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as currently used by the Company, being converged with International Financial Reporting Standards (IFRS) over a transitional period, with a changeover date for the fiscal year beginning on January 1, 2011. The Company is in the process of completing the scoping phase of its IFRS changeover plan, which has a detailed timeline for assessing resourcing and training, analyzing key differences and selecting accounting policies under IFRS and IFRS 1 exemptions. The Company plans to assess the impact on accounting policies, data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, during the period prior to the changeover date.

SHAREHOLDER INFORMATION

As at June 30, 2008, Petro-Canada's outstanding common shares totalled 484.4 million and averaged 483.8 million during the second quarter of 2008. These figures compare with outstanding common shares of 488.8 million as at June 30, 2007 and average shares outstanding of 493.1 million for the quarter ended June 30, 2007.

Petro-Canada will hold a conference call to discuss these results with investors on Thursday, July 24, 2008 at 9:00 a.m. eastern daylight time (EDT). To participate, please call 1-866-898-9626 (toll-free in North America), 00-800-8989-6323 (toll-free internationally), or 416-340-2216 at 8:55 a.m. EDT. Media are invited to listen to the call by dialing 1-866-540-8136 (toll-free in North America) or 416-340-8010. Media are invited to ask questions at the end of the call. A live audio broadcast of the conference call will be available on Petro-Canada's website at http://www.petro-canada.ca/en/investors/845.aspx on July 24, 2008 at 9:00 a.m. EDT. Those who are unable to listen to the call live may listen to a recording of the call approximately one hour after its completion by dialing 1-800-408-3053 (toll-free in North America) or 416-695-5800 (pass code number 3264059#). Approximately one hour after the call, a recording will be available on Petro-Canada's website.

SELECT UPSTREAM OPERATING DATA
June 30, 2008

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	**2008**	2007
Before Royalties				
Crude oil and NGL production net *(thousand barrels/day (Mb/d))*				
North American Natural Gas	**13.0**	12.6	**13.0**	12.5
Oil Sands	**53.9**	52.4	**54.7**	56.0
International & Offshore				
East Coast Canada	**90.4**	108.4	**91.3**	102.8
International				
North Sea	**89.4**	84.7	**93.4**	74.7
Other International	**49.6**	46.2	**50.1**	46.4
	296.3	304.3	**302.5**	292.4
Natural gas production net, excluding injectants *(MMcf/d)*				
North American Natural Gas	**582**	599	**584**	602
International				
North Sea	**60**	49	**59**	58
Other International	**63**	73	**66**	74
	705	721	**709**	734
Total production *(Mboe/d)* net before royalties [1]	**414**	425	**421**	415
After Royalties				
Crude oil and NGL production net *(Mb/d)*				
North American Natural Gas	**10.0**	10.0	**9.9**	9.8
Oil Sands	**49.1**	47.6	**49.8**	51.4
International & Offshore				
East Coast Canada	**66.5**	95.1	**69.0**	90.9
International				
North Sea	**89.4**	84.7	**93.4**	74.7
Other International	**24.6**	41.8	**32.2**	41.6
	239.6	279.2	**254.3**	268.4
Natural gas production net, excluding injectants *(MMcf/d)*				
North American Natural Gas	**456**	470	**461**	473
International				
North Sea	**60**	49	**59**	58
Other International	**63**	53	**66**	74
	579	572	**586**	605
Total production *(Mboe/d)* net after royalties [1]	**336**	375	**352**	369

1 Natural gas converted at six Mcf of natural gas to one bbl of oil.

AVERAGE UPSTREAM PRICE REALIZED
June 30, 2008

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	**2008**	2007
Crude oil and NGL *($/bbl)*				
North American Natural Gas	**112.11**	63.74	**100.65**	60.92
Oil Sands	**108.61**	56.32	**94.39**	54.40
International & Offshore				
East Coast Canada	**126.35**	75.29	**111.89**	70.81
International				
North Sea	**113.47**	70.31	**103.48**	68.73
Other International	**121.06**	75.31	**110.08**	71.01
Total crude oil and NGL	**117.22**	70.14	**104.67**	66.73
Natural gas *($/Mcf)*				
North American Natural Gas	**9.64**	6.87	**8.57**	7.13
International				
North Sea	**11.18**	7.54	**10.98**	8.13
Other International	**5.73**	4.59	**5.28**	4.76
Total natural gas	**9.55**	6.79	**8.56**	7.06

EFFECTIVE ROYALTY RATES
June 30, 2008

	Three months ended June 30,		Six months ended June 30,	
(% of sales revenues)	**2008**	2007	**2008**	2007
North American Natural Gas	**22%**	22%	**21%**	21%
Oil Sands	**9%**	9%	**9%**	8%
International & Offshore				
East Coast Canada	**26%**	12%	**24%**	12%
International				
North Sea	**–**	–	**–**	–
Other International	**42%**	13%	**29%**	8%
Total	**19%**	12%	**16%**	11%

SELECT DOWNSTREAM OPERATING DATA
June 30, 2008

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	**2008**	2007
Petroleum product sales *(thousands of cubic metres/day – m^3/d)*				
Gasoline				
Eastern Canada	**13.4**	13.9	**13.1**	13.5
Western Canada	**10.0**	10.5	**10.4**	10.1
	23.4	24.4	**23.5**	23.6
Distillate				
Eastern Canada	**8.2**	8.2	**8.6**	9.1
Western Canada	**9.0**	9.7	**9.9**	11.2
	17.2	17.9	**18.5**	20.3
Other, including petrochemicals	**11.2**	9.4	**10.0**	8.5
Total petroleum product sales	**51.8**	51.7	**52.0**	52.4
Crude oil processed by Petro-Canada *(thousands of m^3/d)*				
Eastern Canada	**19.2**	20.1	**19.4**	19.8
Western Canada	**19.8**	21.0	**20.5**	20.2
Total crude oil processed by Petro-Canada	**39.0**	41.1	**39.9**	40.0
Average refinery utilization *(%)*	**96**	102	**99**	99
Downstream net earnings after-tax *(cents/litre)*	**6.4**	5.5	**5.1**	4.7

AVERAGE DOWNSTREAM PRICES
June 30, 2008

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	**2008**	2007
Rack prices *(Canadian cents/litre)*				
Gasoline				
Eastern Canada	**88.22**	69.53	**79.76**	64.01
Western Canada	**89.92**	72.98	**80.07**	64.96
Distillate				
Eastern Canada	**102.61**	63.51	**92.51**	61.52
Western Canada	**101.59**	65.16	**91.06**	64.82
Pump prices (*Canadian cents/litre, excluding taxes*)				
Gasoline				
Eastern Canada	**94.24**	74.48	**85.19**	67.35
Western Canada	**99.81**	83.21	**89.96**	75.74

SHARE INFORMATION
June 30, 2008

		Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Weighted-average common shares outstanding *(millions)*		**483.8**	493.1	**483.8**	495.1
Weighted-average diluted common shares outstanding *(millions)*		**488.1**	498.3	**488.0**	500.2
Net earnings	– basic *($/share)*	**3.10**	1.71	**5.32**	2.90
	– diluted *($/share)*	**3.07**	1.70	**5.27**	2.87
Cash flow from operating activities *($/share)*		**5.12**	2.91	**8.09**	5.25
Dividends *($/share)*		**0.13**	0.13	**0.26**	0.26
Toronto Stock Exchange:					
Share price [1]	– High	**60.00**	57.20	**60.00**	57.20
	– Low	**44.69**	45.10	**42.77**	41.02
	– Close at June 30	**57.11**	56.75	**57.11**	56.75
Shares traded *(millions)*		**146.8**	125.0	**302.7**	288.3
New York Stock Exchange:					
Share price [2]	– High	**61.03**	53.27	**61.03**	53.27
	– Low	**43.70**	38.91	**41.95**	34.91
	– Close at June 30	**55.75**	53.16	**55.75**	53.16
Shares traded *(millions)*		**88.9**	37.8	**174.9**	81.7

1 Share prices are in Canadian dollars and represent the closing price.
2 Share prices are in U.S. dollars and represent the closing price.

SELECT FINANCIAL DATA
June 30, 2008
(unaudited, millions of Canadian dollars)

	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Net earnings (loss)				
Upstream				
North American Natural Gas	**$ 100**	$ 81	**$ 174**	$ 193
Oil Sands	**177**	34	**289**	77
International & Offshore				
East Coast Canada	**385**	334	**760**	590
International	**672**	195	**1,008**	204
Downstream	**300**	259	**484**	443
Shared Services	**(136)**	(58)	**(141)**	(72)
Net earnings	**$ 1,498**	$ 845	**$ 2,574**	$ 1,435
Cash flow from operating activities	**$ 2,479**	$ 1,435	**$ 3,914**	$ 2,601
Average capital employed [1]				
Upstream			**$ 8,961**	$ 7,877
Downstream			**6,381**	4,659
Shared Services			**950**	338
Total Company			**$ 16,292**	$ 12,874
Return on capital employed *(%)* [1]				
Upstream			**36.6**	25.2
Downstream			**10.5**	15.1
Total Company			**24.5**	20.2
Return on equity *(%)* [1]			**29.7**	24.4
Debt			**$ 3,934**	$ 2,532
Cash and cash equivalents			**$ 2,241**	$ 904
Debt-to-cash flow from operating activities *(times)* [1]			**0.8**	0.6
Debt-to-debt plus equity *(%)*			**20.7**	18.6

1 Calculated on a 12-month rolling basis.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*
For the periods ended June 30
(millions of Canadian dollars, except per share amounts)

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Revenue				
Operating	$ 7,766	$ 5,529	$ 14,383	$ 10,396
Investment and other income (expense) *(Notes 4 and 6)*	(120)	(51)	(151)	(77)
	7,646	5,478	14,232	10,319
Expenses				
Crude oil and product purchases	3,775	2,522	6,738	4,830
Operating, marketing and general	1,092	986	1,935	1,813
Exploration	185	100	328	242
Depreciation, depletion and amortization	472	516	995	957
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	15	(124)	70	(141)
Interest	47	41	95	83
	5,586	4,041	10,161	7,784
Earnings before income taxes	2,060	1,437	4,071	2,535
Provision for income taxes				
Current	813	606	1,657	1,097
Future *(Note 5)*	(251)	(14)	(160)	3
	562	592	1,497	1,100
Net earnings	$ 1,498	$ 845	$ 2,574	$ 1,435
Earnings per share *(Note 7)*				
Basic	$ 3.10	$ 1.71	$ 5.32	$ 2.90
Diluted	$ 3.07	$ 1.70	$ 5.27	$ 2.87

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*
For the periods ended June 30
(millions of Canadian dollars)

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Net earnings	$ 1,498	$ 845	$ 2,574	$ 1,435
Other comprehensive income, net of tax				
Change in foreign currency translation adjustment	(49)	(203)	158	(196)
Comprehensive income	$ 1,449	$ 642	$ 2,732	$ 1,239

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*
For the periods ended June 30
(millions of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Operating activities				
Net earnings	$ 1,498	$ 845	$ 2,574	$ 1,435
Items not affecting cash flow from operating activities:				
Depreciation, depletion and amortization	472	516	995	957
Future income taxes *(Note 5)*	(251)	(14)	(160)	3
Accretion of asset retirement obligations	18	17	37	34
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	15	(124)	70	(141)
(Gain) loss on sale of assets *(Notes 4 and 6)*	134	(8)	130	(70)
Unrealized losses related to Buzzard derivative contracts	-	40	-	128
Other	(44)	7	(33)	7
Exploration expenses	137	71	218	163
Decrease in non-cash working capital related to operating activities	500	85	83	85
Cash flow from operating activities	2,479	1,435	3,914	2,601
Investing activities				
Expenditures on property, plant and equipment and exploration	(2,141)	(768)	(3,157)	(1,484)
Proceeds from sale of assets *(Note 6)*	33	12	45	94
Increase in other assets	-	(15)	-	(32)
(Increase) decrease in non-cash working capital related to investing activities	907	(92)	941	(151)
Cash flow used in investing activities	(1,201)	(863)	(2,171)	(1,573)
Financing activities				
Decrease in short-term notes payable *(Note 8)*	(431)	-	(109)	-
Proceeds from issue of long-term debt *(Note 8)*	1,482	-	1,482	-
Repayment of long-term debt *(Note 8)*	(300)	(1)	(996)	(3)
Proceeds from issue of common shares *(Note 9)*	13	18	16	24
Purchase of common shares *(Note 9)*	-	(428)	-	(515)
Dividends on common shares	(63)	(64)	(126)	(129)
Cash flow from (used in) financing activities	701	(475)	267	(623)
Increase in cash and cash equivalents	1,979	97	2,010	405
Cash and cash equivalents at beginning of period	262	807	231	499
Cash and cash equivalents at end of period	$ 2,241	$ 904	$ 2,241	$ 904

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET *(unaudited)*
As at June 30, 2008
(millions of Canadian dollars)

	June 30, 2008	December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	$ 2,241	$ 231
Accounts receivable	3,232	1,973
Income taxes receivable	-	280
Inventories *(Note 3)*	2,335	668
Future income taxes	25	26
	7,833	3,178
Property, plant and equipment, net *(Notes 5 and 6)*	21,482	19,497
Goodwill	796	731
Other assets	415	446
	$ 30,526	$ 23,852
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities *(Note 5)*	$ 4,876	$ 3,512
Income taxes payable	991	-
Short-term notes payable *(Note 8)*	-	109
Current portion of long-term debt *(Note 8)*	2	2
	5,869	3,623
Long-term debt *(Note 8)*	3,932	3,339
Other liabilities *(Note 5)*	1,128	717
Asset retirement obligations	1,354	1,234
Future income taxes *(Notes 3 and 5)*	3,195	3,069
Shareholders' equity		
Common shares *(Note 9)*	1,383	1,365
Contributed surplus *(Note 9)*	22	24
Retained earnings	13,696	10,692
Accumulated other comprehensive income		
Foreign currency translation adjustment	(53)	(211)
	15,048	11,870
	$ 30,526	$ 23,852

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*
For the periods ended June 30
(millions of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Retained earnings at beginning of period	$ 12,261	$ 9,090	$ 10,692	$ 8,565
Cumulative effect of adopting new accounting standards *(Note 3)*	-	-	556	-
Net earnings	1,498	845	2,574	1,435
Dividends on common shares	(63)	(64)	(126)	(129)
Excess cost for normal course issuer bid *(Note 9)*	-	(45)	-	(45)
Retained earnings at end of period	$ 13,696	$ 9,826	$ 13,696	$ 9,826

See accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars)

1. SEGMENTED INFORMATION
Three months ended June 30,

	Upstream															
					International & Offshore											
	North American Natural Gas		Oil Sands		East Coast Canada		International		Downstream		Shared Services		Eliminations[4]		Consolidated	
	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007
Revenue																
Sales to customers	$ 581	$ 359	$ 589	$ 147	$ 820	$ 780	$ 1,295	$ 911	$ 4,481	$ 3,332	$ -	$ -	$ -	$ -	$ 7,766	$ 5,529
Investment and other income (expense) [1]	(146)	4	(3)	2	(3)	(6)	28	(39)	(24)	(1)	28	(11)	-	-	(120)	(51)
Inter-segment sales	127	83	381	221	108	109	-	-	4	3	-	-	(620)	(416)	-	-
Segmented revenue	562	446	967	370	925	883	1,323	872	4,461	3,334	28	(11)	(620)	(416)	7,646	5,478
Expenses																
Crude oil and product purchases[2]	138	62	511	124	222	211	-	-	2,942	2,121	-	-	(38)	4	3,775	2,522
Inter-segment transactions	1	2	6	6	2	2	-	-	611	406	-	-	(620)	(416)	-	-
Operating, marketing and general	132	120	170	156	55	59	112	115	410	358	213	178	-	-	1,092	986
Exploration	21	41	-	5	-	5	164	49	-	-	-	-	-	-	185	100
Depreciation, depletion and amortization	118	109	26	40	85	111	165	180	77	72	1	4	-	-	472	516
Unrealized (gain) loss on translation of foreign currency denominated long-term debt											15	(124)	-		15	(124)
Interest	-										47	41			47	41
	410	334	713	331	364	388	441	344	4,040	2,957	276	99	(658)	(412)	5,586	4,041
Earnings (loss) before income taxes	152	112	254	39	561	495	882	528	421	377	(248)	(110)	38	(4)	2,060	1,437
Provision for income taxes																
Current	33	41	55	(16)	185	187	513	368	67	61	(40)	(34)	-	(1)	813	606
Future (Note 5)	19	(10)	22		(9)	(26)	(303)	(35)	54		(34)	(21)	-	-	(251)	(14)
	52	31	77	5	176	161	210	333	121	118	(74)	(55)	-	(1)	562	592
Net earnings (loss)	$ 100	$ 81	$ 177	$ 34	$ 385	$ 334	$ 672	$ 195	$ 300	$ 259	$ (174)	$ (55)	$ 38	$ (3)	$ 1,498	$ 845
Expenditures on property, plant and equipment and exploration [3]	$ 91	$ 116	$ 225	$ 106	$ 44	$ 48	$ 1,269	$ 172	$ 503	$ 319	$ 9	$ 7	$ -	$ -	$ 2,141	$ 768
Cash flow from operating activities	$ 379	$ 247	$ 162	$ 160	$ 670	$ 346	$ 1,031	$ 356	$ 41	$ 320	$ 196	$ 6	$ -	$ -	$ 2,479	$ 1,435
Total assets	$ 4,037	$ 4,032	$ 4,235	$ 2,985	$ 2,140	$ 2,369	$ 7,555	$ 5,766	$10,957	$ 7,293	$ 1,674	$ 708	$ (72)	$ (7)	$30,526	$23,146

1 Investment and other income (expense) for the International segment includes unrealized losses related to the Buzzard derivative contracts of $nil for the three months ended June 30, 2008 ($40 million for the three months ended June 30, 2007) *(Note 4)*.
2 Downstream crude oil and product purchases accounts for substantially all of the Downstream inventories recognized as an expense during the period.
3 Consolidated expenditures include capitalized interest in the amount of $15 million for the three months ended June 30, 2008 ($7 million for the three months ended June 30, 2007).
4 Eliminations relate to sales between segments recorded at transfer prices based on current market prices, and to unrealized inter-segment profits in inventories. Prior period figures have been reclassified to conform to the current period's presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars)

1. SEGMENTED INFORMATION
Six months ended June 30,

	Upstream															
					International & Offshore											
	North American Natural Gas		Oil Sands		East Coast Canada		International		Downstream		Shared Services		Eliminations[4]		Consolidated	
	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007
Revenue																
Sales to customers	$ 1,011	$ 708	$ 934	$ 313	$ 1,502	$ 1,381	$ 2,689	$ 1,575	$ 8,247	$ 6,419	$ -	$ -	$ -	$ -	$14,383	$10,396
Investment and other income (expense)[1]	(143)	65	(1)	-	(2)	(6)	(3)	(129)	(32)	(4)	30	(3)	-		(151)	(77)
Inter-segment sales	226	168	678	443	312	238	-	-	8	7	-	-	(1,224)	(856)	-	-
Segmented revenue	1,094	941	1,611	756	1,812	1,613	2,686	1,446	8,223	6,422	30	(3)	(1,224)	(856)	14,232	10,319
Expenses																
Crude oil and product purchases[2]	231	103	759	254	410	387	-	-	5,381	4,079	-	-	(43)	7	6,738	4,830
Inter-segment transactions	3	4	14	10	4	4	-	-	1,203	838	-	-	(1,224)	(856)	-	-
Operating, marketing and general	260	244	374	287	112	118	242	277	814	710	133	177	-	-	1,935	1,813
Exploration	71	97	5	24	-	9	252	112	-	-	-	-	-	-	328	242
Depreciation, depletion and amortization	272	217	53	79	182	214	335	298	152	141	1	8	-	-	995	957
Unrealized (gain) loss on translation of foreign currency denominated long-term debt											70	(141)	-		70	(141)
Interest	-										95	83			95	83
	837	665	1,205	654	708	732	829	687	7,550	5,768	299	127	(1,267)	(849)	10,161	7,784
Earnings (loss) before income taxes	257	276	406	102	1,104	881	1,857	759	673	654	(269)	(130)	43	(7)	4,071	2,535
Provision for income taxes																
Current	60	102	70	(10)	362	325	1,160	626	90	117	(85)	(61)	-	(2)	1,657	1,097
Future (Note 5)	23	(19)	47		(18)	(34)	(311)	(71)	99		-	(2)	-	-	(160)	3
	83	83	117	25	344	291	849	555	189	211	(85)	(63)	-	(2)	1,497	1,100
Net earnings (loss)	$ 174	$ 193	$ 289	$ 77	$ 760	$ 590	$ 1,008	$ 204	$ 484	$ 443	$ (184)	$ (67)	$ 43	$ (5)	$ 2,574	$ 1,435
Expenditures on property, plant and equipment and exploration[3]	$ 258	$ 321	$ 403	$ 196	$ 82	$ 86	$ 1,520	$ 329	$ 881	$ 540	$ 13	$ 12	$ -	$ -	$ 3,157	$ 1,484
Cash flow from (used in) operating activities	$ 578	$ 406	$ 328	$ 229	$ 1,155	$ 827	$ 1,537	$ 633	$ 25	$ 534	$ 291	$ (28)	$ -	$ -	$ 3,914	$ 2,601
Total assets	$ 4,037	$ 4,032	$ 4,235	$ 2,985	$ 2,140	$ 2,369	$ 7,555	$ 5,766	$10,957	$ 7,293	$ 1,674	$ 708	$ (72)	$ (7)	$30,526	$23,146

1 Investment and other income (expense) for the International segment includes unrealized losses related to the Buzzard derivative contracts of $nil for the six months ended June 30, 2008 ($128 million for the six months ended June 30, 2007) *(Note 4)*.
2 Downstream crude oil and product purchases accounts for substantially all of the Downstream inventories recognized as an expense during the period.
3 Consolidated expenditures include capitalized interest in the amount of $28 million for the six months ended June 30, 2008 ($13 million for the six months ended June 30, 2007).
4 Eliminations relate to sales between segments recorded at transfer prices based on current market prices, and to unrealized inter-segment profits in inventories. Prior period figures have been reclassified to conform to the current period's presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

2. BASIS OF PRESENTATION

The note disclosure requirements for annual financial statements provide additional disclosure to that required for interim financial statements. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the December 31, 2007 audited Consolidated Financial Statements. The interim Consolidated Financial Statements are presented in accordance with Canadian generally accepted accounting principles (GAAP) and follow the accounting policies summarized in the notes to the annual Consolidated Financial Statements, except for changes as described in Note 3.

3. CHANGES IN ACCOUNTING POLICIES

In 2006, Canada's Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as currently used by the Company, being converged with International Financial Reporting Standards (IFRS) over a transitional period, with a changeover date for the fiscal year beginning on January 1, 2011. Public companies in Canada currently have the option to either converge with IFRS or adopt United States GAAP, provided they are a United States Securities and Exchange Commission registrant. The Company has elected to converge with IFRS and is in the process of completing the scoping phase of its changeover plan, which has a detailed timeline for assessing resources and training, analyzing key differences and selecting accounting policies.

The Company adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 1535, *Capital Disclosures*; Section 3031, *Inventories*; Section 3862, *Financial Instruments – Disclosures*; and Section 3863, *Financial Instruments – Presentation* on January 1, 2008.

As a result of adopting CICA Section 1535, *Capital Disclosures*, the Company now discloses details about its capital management (Note 12).

As a result of adopting CICA Section 3031, *Inventories*, the Company now assigns costs to its crude oil and refined petroleum products inventories on a “first-in, first-out” (FIFO) basis. Previously, costs were assigned to these inventories on a “last-in, first-out” (LIFO) basis. In accordance with the transitional provisions of this new accounting standard, the Company has elected to adjust 2008 opening retained earnings by the difference in the measurement of 2008 opening inventory and not restate prior period amounts. As such, the following balance sheet categories were impacted on January 1, 2008:

	Increase
Inventories	$ 812
Future income taxes liability	256
Retained earnings	556

As a result of adopting CICA Section 3862, *Financial Instruments – Disclosures*, the Company has expanded its financial risks and financial instruments disclosures (Note 13).

There is no other material impact on the Consolidated Financial Statements from adoption of these new standards.

4. INVESTMENT AND OTHER INCOME (EXPENSE)

Investment and other income (expense) consists of the following amounts:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Foreign exchange gains (losses)	$ 42	$ (20)	$ 20	$ (26)
Loss on Downstream derivative contracts *(Note 13)*	(31)	(8)	(44)	(13)
Unrealized losses related to Buzzard derivative contracts	-	(40)	-	(128)
Gain (loss) on sale of assets *(Note 6)*	(134)	8	(130)	70
Other	3	9	3	20
Total investment and other income (expense)	$ (120)	$ (51)	$ (151)	$ (77)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

5. LIBYA EXPLORATION AND PRODUCTION SHARING AGREEMENTS

On June 19, 2008, the Company signed six new Exploration and Production Sharing Agreements (EPSAs) with the Libya National Oil Corporation (NOC) to convert its existing concession agreements and old EPSA into new EPSA IV agreements. The new EPSAs were ratified as of the signing with an effective date of January 1, 2008. The new EPSAs will have an expected duration of 30 years and will enable the Company to implement jointly with the NOC the redevelopment of major fields and conduct a 100% operated exploration program in the Libyan Sirte Basin.

The Company will pay a signature bonus of $1 billion US in several instalments with the first instalment of $500 million US paid on July 17, 2008 and the remaining instalments to be paid through 2013. This cost has been discounted to $951 million based on this payout schedule using the Company's estimated cost of debt at the time of acquisition. The discounted acquisition cost was recorded as $533 million in accounts payable and accrued liabilities and $418 million in other liabilities.

Net earnings for the three months ended June 30, 2008 include a $230 million future income tax recovery which the Company recognized on ratification of the new EPSAs, and a $47 million after-tax adjustment to recognize incremental earnings on properties covered by the old agreements based on the financial terms of the new EPSAs relating to the period January 1 to March 31, 2008, which could not be recognized until ratification on June 19, 2008.

6. SALE OF ASSETS

In June 2008, the Company completed the sale of its Minehead assets in Western Canada, which are part of the Company's North American Natural Gas business segment, resulting in a loss on sale of $153 million ($112 million after-tax). The sale of these assets is aligned with North American Natural Gas' strategy to continuously optimize the assets in its portfolio. The loss is included in Investment and other income (expense) in the Consolidated Statement of Earnings.

7. EARNINGS PER SHARE

The following table provides the number of common shares used in calculating earnings per share amounts:

	Three months ended June 30,		Six months ended June 30,	
(millions)	2008	2007	2008	2007
Weighted-average number of common shares outstanding - basic	483.8	493.1	483.8	495.1
Effect of dilutive stock options	4.3	5.2	4.2	5.1
Weighted-average number of common shares outstanding - diluted	488.1	498.3	488.0	500.2

8. LONG-TERM DEBT

	Maturity	June 30, 2008	December 31, 2007
Debentures and notes			
6.80% unsecured senior notes ($900 million US)	2038	$ 905	$ -
5.95% unsecured senior notes ($600 million US)	2035	595	577
5.35% unsecured senior notes ($300 million US)	2033	258	248
7.00% unsecured debentures ($250 million US)	2028	245	237
7.875% unsecured debentures ($275 million US)	2026	275	267
9.25% unsecured debentures ($300 million US)	2021	303	294
6.05% unsecured debentures ($600 million US)	2018	605	-
5.00% unsecured senior notes ($400 million US)	2014	404	391
4.00% unsecured senior notes ($300 million US)	2013	287	275
Syndicated credit facilities	2012	-	995
Capital leases	2008-2022	57	57
		3,934	3,341
Current portion		(2)	(2)
		$ 3,932	$ 3,339

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

8. LONG-TERM DEBT, *continued*

On March 31, 2008, the Company filed a final shelf prospectus for the offering of up to $4 billion US of debt securities with the securities commission or equivalent regulatory authority in each of the provinces and territories of Canada. On April 1, 2008, the same was filed with the United States Securities and Exchange Commission. In May 2008, the Company completed a public offering of debt securities under this prospectus in the form of $600 million US 6.05% 10-year unsecured senior notes due May 15, 2018 and $900 million US 6.80% 30-year unsecured senior notes due May 15, 2038. The net proceeds of this offering were used to repay the Company's short-term notes payable and indebtedness outstanding under its syndicated credit facilities. The balance was added to the Company's working capital to fund future capital expenditures.

At June 30, 2008, the Company had in place revolving, committed syndicated credit facilities totalling $3,570 million (December 31, 2007 – $2,200 million) which mature in 2013 and revolving bilateral demand credit facilities of $766 million (December 31, 2007 – $1,500 million). At June 30, 2008, a total of $285 million of the credit facilities was used for letters of credit and overdraft coverage.

At June 30, 2008, the Company had repaid all amounts previously drawn on its syndicated and demand credit facilities. At December 31, 2007, the Company had drawn on its syndicated credit facilities for $995 million and on its demand credit facilities for $109 million, all in the form of Canadian dollar Bankers' Acceptances.

9. SHAREHOLDERS' EQUITY

Changes in common shares and contributed surplus were as follows:

	Shares	Amount	Contributed Surplus
Balance at December 31, 2007	483,459,119	1,365	24
Issued under employee stock option and share purchase plans	924,922	18	(2)
Repurchased under normal course issuer bid	-	-	-
Balance at June 30, 2008	484,384,041	1,383	22

The Company has in place a normal course issuer bid (NCIB) program for the repurchase of its outstanding common shares. This program was renewed in June 2008 to repurchase up to 24 million outstanding common shares during the period from June 22, 2008 to June 21, 2009, subject to certain conditions. During the three and six months ended June 30, 2008, the Company did not repurchase any common shares. For the three and six months ended June 30, 2007, the Company repurchased 8,000,000 common shares at a cost of $428 million and 10,000,000 common shares at a cost of $515 million, respectively. For the three and six months ended June 30, 2007, the excess of the purchase price over the carrying amount of the shares repurchased was recorded as a $361 million and $442 million reduction of contributed surplus, respectively and a $45 million reduction of retained earnings for both the three and six months ended June 30, 2007.

10. STOCK-BASED COMPENSATION

The total stock-based compensation expense recorded was $189 million and $92 million for the three and six months ended June 30, 2008, respectively ($153 million and $139 million for the three and six months ended June 30, 2007).

(a) Stock Options and Performance Share Units (PSUs)

Changes in the number of outstanding stock options and PSUs were as follows:

	Stock Options		PSUs
	Number	Weighted-Average Exercise Price	Number
Balance at December 31, 2007	21,035,064	$ 34	1,166,044
Granted	3,460,200	47	239,670
Exercised for common shares	(924,922)	17	n/a
Surrendered for cash payment	(860,604)	35	n/a
Cancelled/Expired	(134,310)	47	(587,533)
Balance at June 30, 2008	22,575,428	$ 37	818,181

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

10. STOCK-BASED COMPENSATION, *continued*

(b) Stock Appreciation Rights (SARs)

Changes in the number of outstanding SARs were as follows:

	SARs	
	Number	Weighted-Average Exercise Price
Balance at December 31, 2007	3,659,450	$ 44
Granted	3,980,480	47
Exercised	(136,705)	44
Cancelled	(191,610)	46
Balance at June 30, 2008	7,311,615	$ 46

11. EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions and provides certain health care and life insurance benefits to its qualifying retirees. The expenses associated with these plans are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Pension Plans:				
Defined benefit plans				
Employer current service cost	$ 10	$ 10	$ 21	$ 20
Interest cost	24	22	47	44
Expected return on plan assets	(27)	(28)	(55)	(56)
Amortization of transitional asset	(2)	(2)	(3)	(3)
Amortization of net actuarial losses	12	11	24	22
	17	13	34	27
Defined contribution plans	6	5	11	9
	$ 23	$ 18	$ 45	$ 36
Other post-retirement plans:				
Employer current service cost	$ 2	$ 2	$ 3	$ 3
Interest cost	4	3	7	6
Amortization of transitional obligation	-	-	1	2
Amortization of net actuarial losses	-	-	1	-
	$ 6	$ 5	$ 12	$ 11

The Company expects to contribute $58 million to its pension plans in 2008.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

12. CAPITAL MANAGEMENT

The Company's capital management strategy is designed to maintain financial strength and flexibility to support profitable growth in all business environments. The Company's capital consists of debt, which is comprised of long-term debt, shareholders' equity and at December 31, 2007, short-term notes payable. The Company measures financial strength and flexibility using two key measures: debt-to-cash flow from operating activities, the key short-term measure, and debt-to-debt plus equity, the key long-term measure. These are calculated as follows:

	June 30, 2008	December 31, 2007
Long-term debt (non-current portion)	$ 3,932	$ 3,339
Add: Current portion of long-term debt	2	2
Total long-term debt	3,934	3,341
Add: Short-term notes payable	-	109
Debt (A)	$ 3,934	$ 3,450
Shareholders' equity	15,048	11,870
Debt plus equity (B)	$ 18,982	$ 15,320
Cash flow from operating activities (C)[1]	$ 4,652	$ 3,339
Debt-to-cash flow from operating activities (A/C) *(times)*	0.8	1.0
Debt-to-debt plus equity (A/B) *(%)*	20.7	22.5

1 Cash flow from operating activities is on a 12-month rolling basis.

At June 30, 2008, the debt-to-cash flow from operating activities ratio was within the Company's target range of no more than 2.0 times. Debt-to-debt plus equity was below the target range of 25% to 35%, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. The Company may exceed target ranges for short periods of time, but always with the goal to return back within the target ranges.

Financial covenants associated with the Company's various bank and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The Company complied with all covenants for the three and six months ended June 30, 2008.

The Company's priority uses of cash are to fund the capital program and profitable growth opportunities, and then to return cash to shareholders through dividends and a share buyback program.

The Company regularly reviews its dividend strategy to ensure the alignment of the dividend policy with shareholder expectations, and financial and growth objectives. Consistent with this objective, on July 23, 2008, the Company declared a 54% increase in its quarterly dividend to $0.20 per share, commencing with the dividend payable on October 1, 2008. During June 2008, the Company renewed its NCIB program for the repurchase of its common shares from June 22, 2008 to June 21, 2009, entitling the Company to purchase up to 5% of its outstanding common shares, subject to certain conditions (Note 9). Due to an increasing capital program, share buybacks are expected to be lower in this and future years, compared with 2006 and 2007.

The Company's capital management strategy has not changed from the prior period.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

13. FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Financial Risks

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and the Company's strategy for managing these risks has not changed significantly from the prior period.

(a) Market Risks

The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate. The Company does not use derivative contracts for speculative purposes.

Commodity Price Risk

The Company is exposed to commodity price risk as fluctuations in crude oil or natural gas prices could have a materially adverse effect on its financial condition, as well as on the value and amount of the Company's reserves. Prices for crude oil and natural gas fluctuate in response to changes in supply and demand, market uncertainty and a variety of other factors beyond the Company's control.

The margins realized for the Company's refined products are also affected by factors such as crude oil price fluctuations due to the impact on refinery feedstock costs, third-party refined product purchases and the demand for refined petroleum products. The Company's ability to maintain product margins in an environment of higher feedstock costs depends on its ability to pass higher costs on to customers. The Company enters into derivative contracts to reduce exposure in its Downstream operations to these margin fluctuations, including margins on fixed-price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined petroleum products. The Company's exposure to these margin fluctuations is limited. As such, the fair value of the outstanding derivative contracts is not material.

Interest Rate Risk

The Company is exposed to interest rate risk as changes in market interest rates affect the fair values of fixed-interest rate liabilities and the cash flows of both floating-interest rate liabilities and future borrowings. Notes, debentures and capital leases all bear interest at fixed rates. Drawings on the syndicated and demand credit facilities and obligations under the securitization program all bear interest at floating rates. The Company regularly reviews the mix of floating and fixed rate debt for consistency with its financing objectives.

Foreign Currency Exchange Risk

Due to the fact that energy commodity prices are primarily in U.S. dollars, the Company's revenues, crude oil and product purchases, and associated accounts receivable, accounts payable and accrued liabilities, and off-balance sheet commitments are affected by the Cdn/U.S. dollar exchange rate. These U.S. dollar denominated accounts receivable and accounts payable and accrued liabilities account for a significant portion of the Company's total accounts receivable and accounts payable and accrued liabilities.

Notwithstanding this, the majority of the Company's foreign currency exchange risk arising from financial instruments typically arises from long-term debt, substantially all of which is in the form of U.S. dollar denominated debentures and notes. This exposure partially mitigates the foreign currency exchange risk arising from U.S. dollar denominated revenues. For the three months ended June 30, 2008, the Company had additional exposure to foreign currency exchange risk from U.S. dollar cash and cash equivalents of approximately $1 billion US.

The Company's International business segment and the U.S. Rockies operations included in the North American Natural Gas business segment expose the Company to fluctuations in foreign currency exchange rates, predominantly U.S. dollars.

13. FINANCIAL RISKS AND FINANCIAL INSTRUMENTS, *continued*

(b) Credit Risk

The Company is exposed to credit risk from its counterparties' abilities to fulfil their obligations to the Company. The Company manages this risk through the establishment of credit policies and limits, which are applied in the selection of counterparties. The Company ensures that it has no significant concentrations of credit risk.

The Company's maximum exposure to credit risk at June 30, 2008 is equal to the carrying amount of its financial assets recorded on the Consolidated Balance Sheet and $480 million of outstanding accounts receivable sold under the Company's securitization program, which has been derecognized from the Consolidated Balance Sheet. The Company carries adequate provisions for expected losses arising from credit risk associated with all financial assets, including the receivables derecognized under the securitization program. These provisions are not material.

(c) Liquidity Risk

The Company is exposed to liquidity risk from the potential inability to generate or obtain sufficient cash and cash equivalents in a timely and cost-effective manner to discharge its financial liabilities as they come due. The Company manages liquidity risk by forecasting cash flows to identify financing requirements, by maintaining committed and demand credit facilities, and by maintaining access to additional financing at competitive rates through capital markets and highly rated financial institutions. Any debt issued by the Company is managed in accordance with specified liquidity and maturity profiles.

Financial Instruments

Excluding debentures, senior notes and capital leases, which are recorded as long-term debt, the fair values of financial instruments equals or approximates their carrying amount. The fair value of debentures, senior notes and capital leases was $3,946 million at June 30, 2008 (December 31, 2007 – $2,500 million) compared with a carrying amount of $3,934 million (December 31, 2007 – $2,346 million). The fair values of debentures, senior notes and capital leases are based on publicly quoted market values for instruments with similar terms and risks.