2005 Quarterly Report

PETRO-CANADA

For immediate release
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(publié également en français)

Business Environment Drives Results, As Growth Projects Progress

Highlights

- Fort Hills oil sands project secures a mining partner
- Terra Nova turnaround successfully completed in early October
- Production on track with guidance

Petro-Canada announced today third quarter earnings from operations adjusted for unusual items of $659 million ($1.27/share), up 38% from $477 million ($0.90/share) in the same quarter of 2004. Third quarter 2005 cash flow was $1,063 million ($2.05/share), compared with $869 million ($1.63/share) in the same quarter of last year. Cash flow is before changes in non-cash working capital.

Net earnings for the third quarter in 2005 were $614 million ($1.19/share), compared with $410 million ($0.77/share) in the same period of 2004. Net earnings include unrealized gains or losses on derivative contracts, together with gains or losses on foreign currency translation and disposal of assets. In the third quarter of 2005, an unrealized mark-to-market loss on derivative contracts associated with the Buzzard acquisition lowered net earnings by $85 million after-tax.

“The excellent business environment and solid operations resulted in strong earnings and cash flow this quarter. With our upstream turnarounds largely complete, full year production is anticipated to come in on guidance,” said Ron Brenneman, president and chief executive officer.

Production of crude oil, natural gas liquids and natural gas averaged 422,000 barrels of oil equivalent/day (boe/d) during the quarter, compared to 435,700 boe/d in the same quarter of 2004. Production guidance for the full year remains at 415,000 to 430,000 boe/d.

“Looking forward, I’m pleased with our progress on strategic projects. We are on track to add production from White Rose, Syncrude, De Ruyter and Buzzard, and we took an important step in our Fort Hills project by securing a very capable mining partner,” said Brenneman. “We are positioning our Downstream business to take advantage of long-term strengthening of light/heavy crude differentials. We are converting the Edmonton refinery to process oil sands based feedstock and evaluating the addition of a coker in Montreal.”

Petro-Canada is one of Canada’s largest oil and gas companies, operating in both the upstream and downstream sectors of the industry in Canada and internationally. Its common shares trade on the Toronto Stock Exchange under the symbol PCA and on the New York Stock Exchange under the symbol PCZ.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A), dated October 27, 2005, is set out in pages 2 to 15 and should be read in conjunction with: the unaudited Consolidated Financial Statements for the three months ended March 31, 2005, the six months ended June 30, 2005 and the nine months ended September 30, 2005; the MD&A for the three and six months ended March 31, 2005 and June 30, 2005; the MD&A for the year ended December 31, 2004; the audited Consolidated Financial Statements for the year ended December 31, 2004; and the 2004 Annual Information Form (AIF) dated March 15, 2005.

NON-GAAP MEASURES

Cash flow, which is expressed as cash flow from operating activities before changes in non-cash working capital, is used by the Company to analyse operating performance, leverage and liquidity. Earnings from operations, which represent net earnings excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market of the derivative contracts associated with the Buzzard acquisition, are used by the Company to evaluate operating performance. Cash flow and earnings from operations do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and, therefore, may not be comparable with the calculations of similar measures for other companies. For reconciliations of the cash flow and earnings from operations amounts to the associated GAAP measure, refer to the tables on page 15 of this MD&A.

BUSINESS ENVIRONMENT

Market prices shown on this and the next page influence average prices realized for crude oil, natural gas liquids (NGL), natural gas and petroleum products as set out in the table on page 14.

In the third quarter of 2005, the price of Dated Brent averaged $61.54 US/barrel (bbl), up 48% from $41.54 US/bbl in the third quarter of 2004. During the same period of 2005, the Canadian dollar averaged $0.83 US, up 9% from $0.77 US in the third quarter of 2004. The net impact of these two changes was a 32% increase in Petro-Canada's corporate-wide realized Canadian dollar prices for crude oil and liquids, from $52.43/bbl in the third quarter of 2004 to $69.01/bbl in the third quarter of 2005.

The increase in international and domestic light crude prices was accompanied by a continuing widening in international and Canadian light/heavy crude price differentials. In the third quarter, the spread between Dated Brent and Mexican Maya widened to $13.96 US/bbl, compared with $9.25 US/bbl in the third quarter of 2004. In Canada, the spread between Edmonton Light and Lloydminster Blend widened to $23.27/bbl in the third quarter of 2005, compared with $16.42/bbl in the third quarter of 2004.

In the third quarter of 2005, Henry Hub natural gas prices averaged $8.25 US/million British thermal units (MMBtu), compared with $5.84 US/MMBtu in the third quarter of 2004. In the same period, AECO natural gas prices averaged $8.52/thousand cubic feet (Mcf), up 23% compared with the average of $6.95/Mcf during the third quarter of 2004. Petro-Canada's realized Canadian dollar prices for its North American Natural Gas business averaged $8.22/Mcf in the third quarter of 2005, compared with $6.60/Mcf in the third quarter of 2004.

Hurricanes Katrina and Rita significantly impacted refining capacity in the U.S. Gulf of Mexico in the third quarter, driving an industry-wide trend of higher cracking margins. The New York Harbour 3-2-1 refinery crack spread averaged $14.43 US/bbl, more than doubling the $6.74 US/bbl posted in the third quarter of 2004. Competitive retail pressure and consumer reaction to higher prices continued to lower marketing margins in the quarter.

The average market prices for the three months and nine months ended September 30 were:

(average for the period)	Three months ended September 30, **2005**	2004	Nine months ended September 30, **2005**	2004
Dated Brent at Sullom Voe *$ US/bbl*	**61.54**	41.54	**53.54**	36.28
West Texas Intermediate (WTI) at Cushing *$ US/bbl*	**63.19**	43.88	**55.40**	39.12
Dated Brent-Maya FOB price differential *$ US/bbl*	**13.96**	9.25	**13.48**	7.10
Edmonton Light *$ Cdn/bbl*	**76.90**	56.50	**68.39**	51.03
Edmonton Light/Lloydminster Blend FOB price differential *$ Cdn/bbl*	**23.27**	16.42	**25.14**	14.85
Natural gas at Henry Hub *$ US/MMBtu*	**8.25**	5.84	**7.12**	5.83
Natural gas at AECO *$ Cdn/Mcf*	**8.52**	6.95	**7.73**	6.98
New York Harbour 3-2-1 crack spread *$ US/bbl*	**14.43**	6.74	**9.62**	7.53
Exchange rate *cents US/$ Cdn*	**83.2**	76.5	**81.7**	75.3

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2004 net earnings had these changes occurred. Amounts are stated 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	45	0.09
Price received for natural gas	$0.25/Mcf	33	0.06
Exchange rate: $ Cdn/$ US refers to impact on upstream earnings from operations (5)	$0.01	(22)	(0.04)
Crude oil and NGL production	1,000 b/d	5	0.01
Natural gas production	10 MMcf/d	9	0.02
Downstream			
New York Harbour 3-2-1 crack spread	$0.10 US/bbl	4	0.01
Light/heavy crude price differential	$1.00/bbl	11	0.02
Corporate			
Exchange rate: $ Cdn/$ US refers to impact of the revaluation of U.S. dollar denominated, long-term debt (6)	$0.01	9	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 quoted on a post-stock dividend basis.

(4) This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent and excludes the impact of the Buzzard derivative contracts.

(5) A strengthening Canadian dollar versus the U.S. dollar has a negative effect on upstream earnings.

(6) A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings. The impact refers to gains or losses on $869 million US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on $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 segment, are deferred and included as part of shareholders' equity.

ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

Earnings Analysis

	Three months ended September 30,				Nine months ended September 30,			
($ millions, except per share amounts) [1]	**2005**	*($/share)*	2004	*($/share)*	**2005**	*($/share)*	2004	*($/share)*
Net earnings	**$ 614**	**$ 1.19**	$ 410	$ 0.77	**$ 1,077**	**$ 2.07**	$ 1,316	$ 2.47
Foreign currency translation	74		54		78		20	
Unrealized loss on Buzzard derivative contracts	(85)		(107)		(569)		(164)	
Gain on asset sales	7		2		16		11	
Earnings from operations	**618**	**1.19**	461	0.87	**1,552**	**2.99**	1,449	2.72
Stock-based compensation	(35)		(7)		(57)		(10)	
Insurance premium surcharges [2]	(11)		–		(46)		–	
Oakville closure costs	3		(9)		2		(35)	
Income tax adjustment	–		–		–		13	
Terra Nova insurance proceeds	2		–		2		31	
Earnings from operations adjusted for unusual items	**$ 659**	**$ 1.27**	$ 477	$ 0. 90	**$ 1,651**	**$ 3.18**	$ 1,450	$ 2.73

(1) Per share amounts are quoted on a post-stock dividend basis.

(2) Insurance premium surcharges include accruals and surcharges for Oil Insurance Ltd. (OIL) and sEnergy Insurance Ltd. policies. OIL is a mutual insurance company that was formed to insure against catastrophic risks. sEnergy Insurance Ltd. is a provider of business interruption and excess property insurance to the energy industry.

Foreign currency translation reflects gains or losses on U.S. dollar denominated long-term debt that are not associated with the self-sustaining International business unit and the U.S. Rockies operations included in the North American Natural Gas business unit. In June 2004, as part of its acquisition of an interest in the Buzzard field in the United Kingdom (U.K.) sector of the North Sea, the Company entered into derivative contracts for half of its share of estimated production for the first 3 ½ years. Buzzard unrealized mark-to-market gains or losses are recorded each quarter because these transactions do not currently qualify for hedge accounting.

Earnings Variances

Earnings from operations adjusted for unusual items in the third quarter of 2005 were $659 million ($1.27/share), compared with $477 million ($0.90/share) in the third quarter of 2004. The increase in third quarter earnings reflects higher realized commodity prices and downstream margins, partially offset by lower upstream volumes, higher operating costs and depreciation, depletion and amortization.

In the third quarter of 2005, earnings from operations included a number of unusual items: a $35 million charge related to the mark-to-market of stock-based compensation; an $11 million insurance premium surcharge; a $3 million recovery related to the consolidation of the Eastern Canada refinery operations; and $2 million of insurance proceeds related to the delayed startup of Terra Nova. The insurance premium surcharge is reflected in operating costs and represents the Company's share of anticipated payments to the OIL mutual insurance company related to Hurricane Katrina. In the third quarter of 2004, earnings from operations included two unusual items: a $7 million charge related to the mark-to-market of stock-based compensation; and a $9 million charge related to the consolidation of the Eastern Canada refinery operations.

Consolidated nine month earnings from operations adjusted for unusual items were $1,651 million ($3.18/share), compared with $1,450 million ($2.73/share) in the same period of 2004. Higher realized commodity prices and downstream margins were partially offset by lower upstream volumes, higher operating and exploration costs, and a stronger Canadian dollar.

During the third quarter of 2005, cash flow was $1,063 million ($2.05/share), up from $869 million ($1.63/share) in the same quarter of 2004. Consolidated nine month cash flow was $2,851 million ($5.49/share), compared with $2,622 million ($4.93/share) in the same period of 2004. The increase in cash flow reflects higher earnings from operations.

UPSTREAM

Production

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

In the third quarter of 2005, production of crude oil, NGL and natural gas averaged 422,000 boe/d, compared with 435,700 boe/d in the third quarter of 2004. Higher production from Oil Sands and U.S. Rockies was more than offset by a planned turnaround at Terra Nova and natural declines in Syrian and Western Canada production.

North American Natural Gas

North American Natural Gas year-to-date production of 763 MMcfe/d is on track to meet annual production targets, with solid operations in both the U.S. Rockies and Western Canada.

In the third quarter of 2005, North American Natural Gas contributed $157 million of earnings from operations adjusted for unusual items, compared with $117 million in the third quarter of 2004. Stronger realized prices and the addition of U.S. Rockies production were partially offset by lower Western Canada volumes, increased operating costs and higher depreciation, depletion and amortization. Increased operating costs in the third quarter of 2005 were primarily due to rising industry-wide cost pressures.

Net earnings from North American Natural Gas were $156 million, up from $117 million in the third quarter of 2004. Net earnings in the third quarter of 2005 included a $1 million charge related to an insurance premium surcharge.

Natural gas commodity prices remained strong in the third quarter of 2005. Western Canada realized natural gas prices averaged $8.33/Mcf, up from $6.62/Mcf in the same quarter of 2004. U.S. Rockies realized natural gas prices converted to Canadian dollars averaged $6.51/Mcf in the third quarter of 2005, up from $6.09/Mcf in the same quarter of 2004.

In the third quarter of 2005, North American Natural Gas production averaged 750 million cubic feet/day of natural gas equivalent (MMcfe/d), compared with 784 MMcfe/d in the same period last year. Western Canada declines more than offset the increase from U.S. Rockies production. Scheduled maintenance activities at Petro-Canada operated natural gas processing facilities proceeded as planned, lowering production by approximately 10 MMcf/d in the third quarter, and are complete for this year. Partner operated scheduled gas plant maintenance is expected to impact fourth quarter production by about 6 MMcf/d.

U.S. Rockies production averaged 52 MMcfe/d in the third quarter of 2005. The U.S. Rockies is on target to drill 260 operated wells in 2005, up from 148 in 2004. In addition, Petro-Canada plans to obtain at least 450 permits for new coal bed methane wells in 2005, with 370 approved by the regulators and 280 applications submitted for consideration. Most of the new wells are in the de-watering phase, with the expectation of new gas production beginning next year and a doubling of production to 100 MMcfe/d by 2007.

East Coast Oil

A 40-day planned turnaround at Terra Nova was completed on schedule and on budget, with production resuming in early October. Production is expected to come on-stream from White Rose by year end.

In the third quarter of 2005, East Coast Oil contributed $220 million of earnings from operations adjusted for unusual items, up 16% from $190 million in the third quarter of 2004. Stronger realized prices were partially offset by decreased production and a lower draw on inventory compared to the third quarter of 2004.

Net earnings from East Coast Oil were $218 million, up from $190 million in the third quarter of 2004. Net earnings in the third quarter of 2005 included a $4 million charge related to an insurance premium surcharge and $2 million of insurance proceeds related to the delayed startup of Terra Nova.

During the third quarter of 2005, East Coast Oil realized crude prices averaged $73.37/bbl, compared with $54.43/bbl in the third quarter of 2004.

In the third quarter of 2005, East Coast Oil production averaged 64,700 b/d, compared with 71,500 b/d during the same period of 2004. Terra Nova's third quarter production averaged 27,300 b/d, compared with 30,200 b/d in the third quarter of 2004. Production was lower due to the 40-day scheduled turnaround at Terra Nova. Hibernia delivered steady reliability with production averaging 37,400 b/d during the third quarter of 2005. In the same quarter of 2004, Hibernia production averaged 41,300 b/d, reflecting exceptional reliability.

Scheduled Turnarounds

The turnaround at Terra Nova was successfully completed in October 2005. The turnaround included regulatory inspections on equipment and modifications to improve the reliability of the gas compression and injection systems. Petro-Canada is taking a staged approach to achieve first quartile reliability at Terra Nova, with a second phase of improvements planned to occur during an extended turnaround in 2006. The 2006 turnaround is in the planning stage and requires government, regulatory and partner review and approval before finalization. The current turnaround plan anticipates relocating the Terra Nova vessel to a dry dock to complete work required for regulatory certification and compliance, for completion of reliability improvements to the gas compression system, and for modifications to enable a larger crew complement for ongoing maintenance. At this time, the total duration of the turnaround is expected to be 70 to 90 days.

A two-day turnaround at Hibernia was successfully completed in the third quarter of 2005.

Terra Nova Royalty Rate

As expected, royalty payments at Terra Nova will increase late this year, reflecting the provincial profit-sensitive royalty regime. In the fourth quarter of 2005, it is expected Terra Nova will be subject to the incremental royalty regime. This will have the effect of increasing royalties from 5% of gross revenues to the equivalent of approximately 24% to 28% of gross revenues.

Other Developments

The White Rose floating production, storage and offloading (FPSO) is currently undergoing offshore hookup and commissioning at the White Rose oilfield, and continues to progress on budget and on schedule for startup around year end. White Rose is expected to produce an average of 25,000 b/d of peak production net to Petro-Canada when fully operational.

Development of the Far East, which is an extension of the Terra Nova field, was approved by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). The first production well in this reservoir is being drilled and is expected to be on-stream in late 2005 or early 2006. The Far East is expected to contribute 40 million bbls to the life-of-field estimate for Terra Nova.

Oil Sands

Record prices and reliable production at MacKay River contributed to a solid quarter. Strategic progress included the addition of a mining partner for the Fort Hills project.

Oil Sands contributed $83 million of earnings from operations adjusted for unusual items in the third quarter of 2005, up from $51 million in the third quarter of 2004. Higher realized prices and production were partially offset by higher operating costs and depreciation, depletion and amortization.

Increased operating costs were primarily due to incentive-based compensation at Syncrude and rising natural gas costs. Higher depreciation, depletion and amortization are due to the Fort Hills and Dover acquisitions.

In the third quarter of 2005, Oil Sands net earnings were $85 million, up from net earnings of $51 million in the third quarter of 2004. Net earnings in the third quarter of 2005 included a $1 million charge related to an insurance premium surcharge and a $3 million gain on the sale of assets.

Syncrude production was lower due to the planned turnaround at the vacuum distillation unit, which began late in the quarter and will last for 52 days. Production averaged 28,600 b/d in the third quarter of 2005, compared with 29,200 b/d in the third quarter of 2004. The turnaround is progressing on time and on budget, and is expected to be completed in November. In September, Syncrude increased its cost estimate to complete the Stage III expansion by 2% to $8.3 billion from $8.1 billion. Syncrude realized prices averaged $77.16/bbl, up from $54.81/bbl in the third quarter of 2004. A number of planned turnarounds are scheduled in the fourth quarter of 2005 to tie-in several units to the Stage III expansion. These turnarounds will not affect production. Syncrude's Stage III expansion is expected to be on-stream in mid-2006. In early 2006, Syncrude royalty payments are expected to increase from 1% of gross revenues to 25% of net revenues.

Record bitumen prices and reliable production at MacKay River delivered a solid quarter. MacKay River reliability during the third quarter exceeded 99%, compared with 88% in the same period of 2004. Production averaged 23,500 b/d in the third quarter, up from 16,200 b/d in the same period of 2004. Work to tie-in a new well pad will continue until year end, contributing to targeted production of 27,000 to 30,000 b/d by late 2006. MacKay River bitumen realized prices averaged $31.98/bbl in the third quarter of 2005, compared with $25.15/bbl in the third quarter of 2004.

Fort Hills

On September 6, 2005, Petro-Canada and UTS Energy Corporation (UTS) entered into an agreement with Teck Cominco Limited (Teck Cominco) that allows Teck Cominco to acquire a 15% interest in the Fort Hills oil sands project. Petro-Canada will remain project operator with a 55% interest, with UTS holding a 30% stake. Teck Cominco will acquire a 15% interest in Fort Hills and pay for their interest by funding $475 million of Petro-Canada's and UTS's future capital expenditures. All transactions are subject to applicable governmental and regulatory approvals and are expected to close by year end. Petro-Canada is in the first phase of work on engineering and investigation of options for the mine, extraction and upgrading. Petro-Canada expects to start the design basis memorandum, which establishes key design parameters and a more detailed project schedule, early in the first quarter of 2006.

International

High prices and production led to a strong financial and operational quarter, while growth prospects progressed in all three regions.

International contributed $127 million of earnings from operations adjusted for unusual items in the third quarter of 2005, compared with $93 million in the third quarter of 2004. Higher realized commodity prices were partially offset by lower production primarily in the North Africa/Near East region, as well as lower liftings.

In the third quarter of 2005, International had net earnings of $40 million, compared with a net loss of $14 million in the third quarter of 2004. Net earnings in the third quarter of 2005 included an $85 million unrealized loss on the Buzzard derivative contracts and a $2 million charge related to an insurance premium surcharge. Net earnings in the third quarter of 2004 included a $107 million unrealized loss on the Buzzard derivative contracts.

International realized commodity prices remained strong during the third quarter of 2005. International crude oil and NGL realized prices averaged $71.63/bbl, compared with $54.13/bbl in the same period of 2004. International realized prices for natural gas averaged $6.71/Mcf in the third quarter of 2005, compared with $4.98/Mcf in the same period of 2004.

During the third quarter, International production averaged 180,200 boe/d, compared with 188,100 boe/d in the third quarter of 2004. This was mainly due to lower production in the North Sea and Syria. International production for the full year is expected to be ahead of guidance.

Northwest Europe

Third quarter production averaged 48,400 boe/d, down from 49,700 boe/d in the same period last year. Production from the U.K. sector of the North Sea averaged 35,400 boe/d in the third quarter of 2005, up from 31,900 boe/d in the same period last year. Higher production was due to the startup of Pict, which added about 18,000 boe/d in the third quarter. This increase was partially offset by the Scott platform turnaround, which was completed in July 2005, and the Triton turnaround, which was completed in August 2005. Pict is expected to produce an average of 15,000 boe/d for the remainder of this year and 10,000 boe/d in 2006. Production in The Netherlands sector of the North Sea averaged 13,000 boe/d in the third quarter of 2005, compared with 17,800 boe/d in the third quarter of 2004. Lower production in The Netherlands was due to natural declines.

Buzzard Development

Petro-Canada's next U.K. North Sea development to come on-stream is the Buzzard field, in which the Company has a 29.9% interest. Progress on the Buzzard field development continues on schedule and on budget, with more than 80% of the construction complete. The summer offshore installation program was successful with three jackets and the wellhead deck installed. A large portion of the subsea infrastructure, including oil and gas export lines, was installed and tie-in work continues through October. Construction is also progressing on the production and utilities decks. First oil is expected near the end of 2006, with peak production of 60,000 boe/d net to Petro-Canada.

Other Developments

In The Netherlands, development of De Ruyter and L5b-C are on schedule and on budget. De Ruyter, a Petro-Canada operated development, is expected to be on-stream in late 2006, with peak production of 10,000 boe/d net to Petro-Canada. L5b-C, a small non-operated asset, is expected to be on-stream in late 2006, with peak production in excess of 3,000 boe/d net to Petro-Canada.

Petro-Canada was awarded eight blocks in the U.K. Continental Shelf 23rd round of licensing. These blocks are located in the Moray Firth, in the greater Buzzard area, and fit the business unit's strategy of building a balanced exploration program. Petro-Canada is the operator and currently has a 90% working interest in these blocks. The blocks will carry a total work program of four commitment wells, plus seismic acquisition and reprocessing.

North Africa/Near East

Production in North Africa/Near East averaged 119,800 boe/d in the third quarter of 2005, down from 126,100 boe/d in the same quarter of 2004. Libyan production averaged 50,400 b/d, compared with 50,500 b/d in the third quarter of 2004. Fire damage to process equipment was repaired and full Libyan production resumed in July 2005. Syrian production averaged 69,400 boe/d, down from 75,100 boe/d due to natural declines in the existing, mature fields.

During the third quarter, exploration activity continued in the North Africa/Near East region. In Syria, the exploration program in block II progressed, a 3D seismic survey was completed and a 2D seismic survey is ongoing. In Algeria, a 3D seismic survey was completed on the Zotti block. In Tunisia, the Company will drill an offshore exploration well in the fourth quarter of 2005.

As part of its ongoing portfolio management process, Petro-Canada is reviewing options for its Al Furat assets in Syria. In September 2005, Petro-Canada opened a data room. A decision on a possible divestiture is expected to be made around year end.

Northern Latin America

Trinidad offshore gas production averaged 72 MMcf/d in the third quarter of 2005, compared with 74 MMcf/d in the third quarter of 2004.

Work on the Trinidad offshore exploration blocks 1a, 1b and 22 progressed with preparation for, and shooting of, two seismic surveys; one on block 1a and 1b in the third quarter and the other on block 22, which is expected to commence in the fourth quarter. These blocks cover 4,258 square kilometres, with block 1a containing four discoveries. The Company expects to invest more than $100 million in the first phase of exploration, which includes shooting a 3D seismic survey and the drilling of six exploration wells.

On September 30, 2005, a declaration of commercial viability was filed for the La Ceiba development in Venezuela. Petro-Canada and its partner, Exxon Mobil Corporation, anticipate filing a provisional development plan by the end of the year.

DOWNSTREAM

The substantial improvement in refining cracking spreads, solid reliability and wider light/heavy crude price differentials contributed to improved earnings in the Downstream business. The marketing segment of the Downstream business continued to face difficulties in recouping the higher cost of crude feedstocks.

The Downstream business contributed $98 million of earnings from operations adjusted for unusual items in the third quarter of 2005, up from $49 million in the same quarter of 2004. The increase in earnings from operations reflects higher gasoline and distillate cracking margins, and improved reliability at the Montreal refinery. These gains were partially offset by higher operating costs primarily due to refinery shutdowns, lower sales volumes, lower asphalt and heavy fuel oil margins, and continued intense retail competition.

The Downstream business recorded third quarter net earnings of $102 million, compared with net earnings of $42 million in the same quarter of 2004. Net earnings in the third quarter of 2005 included a $3 million charge related to an insurance premium surcharge, a $3 million recovery related to the consolidation of the Eastern Canada refinery operations, and a $4 million gain on the sale of assets. Net earnings in the third quarter of 2004 included a $9 million charge related to the consolidation of Eastern Canada refinery operations and a $2 million gain on the sale of assets.

The average New York Harbour 3-2-1 refinery crack spread was $14.43 US/bbl in the third quarter of 2005, up from $6.74 US/bbl in the third quarter of 2004. The average international light/heavy crude price differential widened to $13.96 US/bbl in the third quarter of 2005, compared with $9.25 US/bbl in 2004.

In the third quarter of 2005, total sales of refined petroleum products were down 7%, compared with the same period last year. The reduced volumes were mainly due to lower sales of asphalt, heavy fuel oil and jet fuel due to the consolidation of Eastern Canada refinery operations.

Refining and supply contributed third quarter 2005 earnings from operations adjusted for unusual items of $101 million, compared with $42 million in the same quarter of 2004. Results were impacted by higher cracking margins and wider light/heavy crude differentials, which were partially offset by lower margins on asphalt and heavy fuel oil.

Marketing recorded third quarter 2005 losses from operations adjusted for unusual items of $3 million, compared with earnings of $7 million in the same quarter of 2004. Marketing margins continued to reflect impacts from rising crude and product costs, and intense competition in several major markets.

Downstream Turnaround Activity

In September, the Montreal refinery commenced a 35-day hydrocracker turnaround, which is expected to be completed early in the fourth quarter. The previously announced 33-day turnaround at the Mississauga lubricants plant was rescheduled from the third quarter to the fourth quarter to enable completion of additional activities during the shutdown.

Edmonton Refinery Conversion

Petro-Canada's Board of Directors recently approved $1.6 billion for the last phase of the project to convert the Edmonton refinery to run exclusively on oil sands based feedstock. Costs based on the completion of preliminary engineering, are up from the original conceptual estimate of $1.2 billion. The increase reflects a more current assessment of refinery integration requirements and industry-wide cost pressures. Project economics remain strong as projected wider light/heavy crude differentials are expected to offset the increase in capital.

CORPORATE

Shared Services recorded net earnings of $13 million in the third quarter of 2005, compared with net earnings of $24 million for the same period in 2004. Third quarter 2005 net earnings included a $35 million mark-to-market charge for stock-based compensation and a $74 million gain on foreign currency translation related to long-term debt. Third quarter 2004 net earnings included a $7 million mark-to-market charge for stock-based compensation and a $54 million gain on foreign currency translation related to long-term debt.

Interest expense was $39 million before-tax during the third quarter of 2005, up from $33 million in the prior year as a result of higher levels of debt.

Cash flow was affected by two items that typically cause differences between earnings and cash flow. Tax deferrals resulting from the Company's upstream partnership increased cash flow by about $70 million in the quarter, compared with a decrease of $35 million in the same period last year. The inventory valuation method prescribed for income tax purposes in the Downstream business decreased third quarter cash flow by approximately $43 million, compared with a decrease of $36 million in 2004.

Shareholder Activities

Normal Course Issuer Bid (NCIB)

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 the share buyback program. During the third quarter of 2005, Petro-Canada purchased a total of 2,400,000 common shares at an average price of $47.97/share for a total cost of approximately $115 million. Year-to-date under the NCIB, the Company purchased a total of 6,333,400 common shares at an average price of $40.65/share for a total cost of approximately $257 million. Petro-Canada renewed its NCIB for the repurchase of its common shares from June 22, 2005 to June 21, 2006, entitling the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions. These share figures are quoted on a post-stock dividend basis.

Stock Dividend

On July 26, 2005, the Board of Directors declared a stock dividend which effectively achieved a two-for-one stock split. The stock dividend was payable on September 14, 2005 to common shareholders of record at the close of business on September 3, 2005, with one additional common share being issued for each outstanding common share held.

Dividend Increased 33%

Commencing with the fourth quarter dividend paid on October 1, 2005, the Company increased the quarterly dividend 33%, from $0.15/share to $0.20/share on a pre-stock dividend basis ($0.10/share on a post-stock dividend basis). Petro-Canada regularly reviews its dividend strategy to ensure the alignment of dividend policy with shareholder expectations, and financial and growth objectives.

Accounting Changes

Effective January 1, 2005, the Company changed the presentation of cash flow in the Consolidated Statement of Cash Flows pursuant to recent interpretations from the U.S. Securities and Exchange Commission (SEC). Previously, all exploration expenses were classified as investing activities. With the change, general and administrative, and geological and geophysical exploration expenses are treated as a reduction of cash flow from operating activities. All prior periods have been restated to reflect this change. The change resulted in a decrease in cash flow from operating activities and an increase in cash flow from investing activities by $26 million for the three months ended September 30, 2005.

LIQUIDITY AND CAPITAL RESOURCES

Petro-Canada's syndicated committed credit facilities totaled $1,500 million at the end of the quarter. The Company also had bilateral demand credit facilities of $419 million. At September 30, 2005, a total of $1,212 million of the credit facilities was used for letters of credit and overdraft coverage. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program.

The Company's unsecured long-term debt securities are rated Baa2 by Moody's Investors Service, BBB by Standard & Poor's and A (low) by Dominion Bond Rating Service. The Company's long-term debt ratings remained unchanged from year-end 2004.

Petro-Canada's cash and cash equivalents were $391 million as at September 30, 2005, compared with $170 million as at December 31, 2004.

Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, the operating working capital deficiency was $470 million at the end of the third quarter, compared with an operating working capital deficiency of $777 million as at December 31, 2004. The working capital deficiency was lower primarily due to an increase in accounts receivable partially offset by an increase in accounts payable.

The Company has certain retail licensee agreements that qualify as variable interest entities as described in Note 17 to the September 30, 2005 Consolidated Financial Statements. These entities are not consolidated as Petro-Canada is not the primary beneficiary and the Company's maximum exposure to losses from these arrangements would not be material.

Commitments and contingent liabilities are disclosed in Note 25 to the 2004 annual Consolidated Financial Statements. There has been no material change in these amounts as at September 30, 2005.

Contractual obligations are summarized in the Company's 2004 annual MD&A. During the third quarter of 2005, total contractual obligations decreased by approximately $340 million from June 30, 2005. The decrease was largely attributable to the lower Canadian dollar equivalent of U.S. dollar debt obligations, as a result of the appreciation in the Canadian dollar.

RISK

Derivative Contracts

As part of its acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea, Petro-Canada entered into a series of derivative contracts related to the future sale of Brent crude oil. Consistent with the rise in oil prices, mark-to-market unrealized losses associated with these Buzzard contracts increased by $85 million after-tax in the third quarter of 2005, compared with $107 million in the third quarter of 2004. As the Buzzard development is not sufficiently advanced to qualify for hedge accounting, unrealized gains or losses are reported every quarter.

As at September 30, 2005, there was no material change in the Company's risks or risk management activities since December 31, 2004. Petro-Canada's risk management activities are conducted according to policies and guidelines established by the Board of Directors. Readers should refer to Petro-Canada's 2004 AIF and the risk management section of the 2004 annual MD&A.

SHAREHOLDER INFORMATION

As at September 30, 2005, Petro-Canada's common shares outstanding totaled 516.9 million and averaged 518.1 million in the third quarter. This compares with average shares outstanding of 531.7 million for the quarter ended September 30, 2004. These share figures are quoted on a post-stock dividend basis.

Petro-Canada will hold a conference call to discuss these results with investors on Thursday, October 27, 2005 at 9:00 a.m. Eastern Time. To participate, please call 1 866 898-9626 or (416) 340-2216 at 8:55 a.m. Media are invited to listen to the call by dialing 1 866 540-8136 or (416) 340-8010 and are invited to ask questions at the end of the call. Those who are unable to listen to the call live may listen to a recording of it approximately one hour after its completion by calling 1 800 408-3053 or (416) 695-5800 (passcode number 3163113). A live audio broadcast of the conference call will be available on Petro-Canada's website at http://www.petro-canada.ca/eng/investor/9259.htm on October 27 at 9:00 a.m. Eastern Time. Approximately one hour after the call, a recording of the call will be available on the website.

Legal Notice – Forward-Looking Information

This quarterly report contains forward-looking statements. Such statements are generally identifiable by the terminology used, such as "plan," "anticipate," "intend," "expect," "estimate," "budget" or other similar wording. Forward-looking statements include, but are not limited to, references to future capital and other expenditures, drilling plans, construction activities, the submission of development plans, seismic activity, refining margins, oil and gas production levels and the sources of growth thereof, results of exploration activities and dates by which certain areas may be developed or may come on-stream, retail throughputs, pre-production and operating costs, reserves estimates, reserves life, natural gas export capacity and environmental matters. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the effects of weather conditions; the results of exploration and development drilling and related activities; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; changes in environmental and other regulations; risks attendant with oil and gas operations; expected rates of return; and other factors, many of which are beyond the control of Petro-Canada. These factors are discussed in greater detail in filings made by Petro-Canada with the Canadian provincial securities commissions and the U.S. SEC.

Readers are cautioned that the foregoing list of important factors affecting forward-looking statements is not exhaustive. Furthermore, the forward-looking statements contained in this quarterly report are made as of the date of this report, and Petro-Canada does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Petro-Canada's staff of qualified reserves evaluators generates the reserves estimates used by the Company. Our reserves staff and management are not considered independent of the Company for purposes of the Canadian provincial securities commissions. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements to permit it to make disclosure in accordance with SEC standards in order to provide comparability with U.S. and other international issuers. Therefore, Petro-Canada's reserves data and other oil and gas formal disclosure is made in accordance with U.S. disclosure requirements and practices and may differ from Canadian domestic standards and practices. Where 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 Mcf: one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The use of terms such as "probable," "possible," "recoverable," or "potential" reserves and resources in this quarterly report does not meet the guidelines of the SEC for inclusion in documents filed with the SEC.

SELECTED OPERATING DATA
September 30, 2005

	Three months ended September 30, 2005	2004	Nine months ended September 30, 2005	2004
Before Royalties				
Crude oil and natural gas liquids production, net *(Mb/d)*				
East Coast Oil	64.7	71.5	73.4	81.4
Oil Sands	52.1	45.4	46.5	44.5
North American Natural Gas (1)	14.0	15.7	14.9	14.8
Northwest Europe	38.7	36.6	33.1	42.3
North Africa/Near East	115.6	122.8	116.5	128.3
	285.1	292.0	284.4	311.3
Natural gas production, net, excluding injectants *(MMcf/d)*				
North American Natural Gas (1)	666	690	674	686
Northwest Europe	58	79	66	89
North Africa/Near East	25	20	26	20
Northern Latin America	72	74	73	71
	821	863	839	866
Total production(2) *(Mboe/d),* net before royalties	422	436	424	456
After Royalties				
Crude oil and natural gas liquids production, net *(Mb/d)*				
East Coast Oil	60.4	68.2	69.4	78.4
Oil Sands	51.6	45.0	46.0	44.1
North American Natural Gas (1)	10.6	11.6	11.1	10.9
Northwest Europe	38.0	36.6	32.6	42.3
North Africa/Near East	62.1	65.2	63.3	67.4
	222.7	226.6	222.4	243.1
Natural gas production, net, excluding injectants *(MMcf/d)*				
North American Natural Gas (1)	527	521	522	521
Northwest Europe	58	79	66	89
North Africa/Near East	4	2	4	3
Northern Latin America	51	49	58	52
	640	651	650	665
Total production (2) *(Mboe/d),* net after royalties	329	335	331	354
Petroleum product sales *(thousands of cubic metres - m^3/d)*				
Gasolines	25.5	25.8	24.7	24.9
Distillates	18.6	18.5	19.2	20.0
Other, including petrochemicals	9.5	13.2	8.9	12.1
	53.6	57.5	52.8	57.0
Crude oil processed by Petro-Canada *(thousands of m^3/d)*	39.7	51.0	41.1	49.3
Average refinery utilization *(%)* (3)	98	103	95	99
Downstream earnings from operations after-tax *(cents/litre)* (4)	1.9	0.9	2.0	1.6

(1) North American Natural Gas includes Western Canada and U.S. Rockies.
(2) Natural gas converted at six Mcf of gas to one bbl of oil.
(3) Includes Oakville capacity pro rated to reflect partial operation of Oakville refinery prior to permanent closure, effective April 11, 2005.
(4) Before additional depreciation and other charges related to the closure of the Oakville refinery.

AVERAGE PRICE REALIZED
September 30, 2005

	Three months ended September 30, 2005	2004	Nine months ended September 30, 2005	2004
Crude oil and natural gas liquids *($/bbl)*				
East Coast Oil	73.37	54.43	62.75	47.85
Oil Sands	56.78	44.23	47.07	40.32
North American Natural Gas (1)	65.51	49.72	58.22	44.92
Northwest Europe	72.70	55.92	65.66	49.01
North Africa/Near East	71.27	53.60	63.55	46.92
Average crude oil and natural gas liquids	69.01	52.43	60.62	46.41
Natural gas *($/Mcf)*				
North American Natural Gas (1)	8.22	6.60	7.38	6.66
Northwest Europe	6.37	5.58	6.91	5.51
North Africa/Near East	6.95	5.35	6.22	4.88
Northern Latin America	6.90	4.24	5.67	4.64
Average natural gas	7.93	6.28	7.16	6.33

SHARE INFORMATION (2)
September 30, 2005

	Three months ended September 30, 2005	2004	Nine months ended September 30, 2005	2004
Weighted-average shares outstanding *(millions)*	518.1	531.7	519.2	532.0
Weighted-average diluted shares outstanding *(millions)*	525.4	538.8	526.2	539.0
Net earnings – Basic *($/share)*	$ 1.19	$ 0.77	$ 2.07	$ 2.47
– Diluted *($/share)*	$ 1.17	$ 0.76	$ 2.05	$ 2.44
Cash flow *($/share)*	$ 2.05	$ 1.63	$ 5.49	$ 4.93
Dividends *($/share)*	$ 0.08	$ 0.08	$ 0.23	$ 0.23
Share price (3) – High	$ 50.80	$ 33.62	$ 50.80	$ 34.33
– Low	$ 40.33	$ 28.20	$ 29.51	$ 27.93
– Close at September 30	$ 48.66	$ 32.87	$ 48.66	$ 32.87
Shares traded (4) *(millions)*	174.2	165.5	482.9	444.4

(1) North American Natural Gas includes Western Canada and U.S. Rockies.
(2) Share information is quoted on a post-stock dividend basis.
(3) Share prices are for trading on the Toronto Stock Exchange (TSX) and represent the closing price.
(4) Total shares traded on the TSX and New York Stock Exchange.

SELECTED FINANCIAL DATA
September 30, 2005
(unaudited, millions of Canadian dollars)

	Three months ended September 30, 2005	Three months ended September 30, 2004	Nine months ended September 30, 2005	Nine months ended September 30, 2004
Earnings				
Upstream				
North American Natural Gas	$ 156	$ 117	$ 376	$ 369
East Coast Oil	218	190	595	558
Oil Sands	82	51	97	110
International	125	93	354	288
Downstream	98	40	291	219
Shared Services	(61)	(30)	(161)	(95)
Earnings from operations	$ 618	$ 461	$ 1,552	$ 1,449
Foreign currency translation	74	54	78	20
Unrealized loss on Buzzard derivative contracts	(85)	(107)	(569)	(164)
Gain (loss) on asset sales	7	2	16	11
Net earnings	$ 614	$ 410	$ 1,077	$ 1,316
Cash flow				
Cash flow from operating activities	$ 1,068	$ 1,135	$ 2,642	$ 3,368
Increase (decrease) in non-cash working capital related to operating activities and other	(5)	(266)	209	(746)
Cash flow	$ 1,063	$ 869	$ 2,851	$ 2,622
Average capital employed				
Upstream			$ 8,342	$ 7,534
Downstream			3,185	2,629
Shared Services			(73)	138
Total Company			$ 11,454	$10,301
Return on capital employed [1] *(%)*				
Upstream			14.3	17.7
Downstream			12.4	9.7
Total Company			14.0	15.6
Operating return on capital employed [1] *(%)*				
Upstream			21.6	19.7
Downstream			12.0	9.6
Total Company			18.2	16.4
Return on equity *(%)*			17.5	19.3
Debt			$ 2,903	$ 2,614
Cash and cash equivalents			$ 391	$ 445
Debt to cash flow [1] *(times)*			0.8	0.8
Debt to debt plus equity *(%)*			24.3	23.8

(1) 12-month rolling average.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*
For the period ended September 30, 2005
(millions of Canadian dollars, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Revenue				
Operating	$ 4,964	$ 3,788	$ 13,130	$ 10,880
Investment and other income (Note 5)	(119)	(166)	(843)	(220)
	4,845	3,622	12,287	10,660
Expenses				
Crude oil and product purchases	2,469	1,807	6,417	4,946
Operating, marketing and general (Note 6)	780	664	2,234	1,988
Exploration	54	49	194	159
Depreciation, depletion and amortization (Note 6)	369	352	1,066	1,050
Unrealized gain on translation of foreign currency denominated long-term debt	(90)	(67)	(95)	(25)
Interest	39	33	112	108
	3,621	2,838	9,928	8,226
Earnings before income taxes	1,224	784	2,359	2,434
Provision for income taxes				
Current	612	412	1,504	1,231
Future (Note 7)	(2)	(38)	(222)	(113)
	610	374	1,282	1,118
Net earnings	$ 614	$ 410	$ 1,077	$ 1,316
Earnings per share (Notes 4 and 8)				
Basic (dollars)	$ 1.19	$ 0.77	$ 2.07	$ 2.47
Diluted (dollars)	$ 1.17	$ 0.76	$ 2.05	$ 2.44

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*
For the period ended September 30, 2005
(millions of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Retained earnings at beginning of period	$ 5,793	$ 4,636	$ 5,408	$ 3,810
Net earnings	614	410	1,077	1,316
Dividends on common shares	(52)	(40)	(130)	(120)
Retained earnings at end of period	$ 6,355	$ 5,006	$ 6,355	$ 5,006

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*
For the period ended September 30, 2005
(millions of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
		(restated)		*(restated)*
Operating activities				
Net earnings	$ 614	$ 410	$ 1,077	$ 1,316
Items not affecting cash flow from operating activities:				
Depreciation, depletion and amortization	369	352	1,066	1,050
Future income taxes	(2)	(38)	(222)	(113)
Accretion of asset retirement obligations	12	13	41	37
Unrealized gain on translation of foreign currency denominated long-term debt	(90)	(67)	(95)	(25)
Gain on disposal of assets (Note 5)	(9)	(2)	(23)	(12)
Unrealized loss associated with the Buzzard derivative contracts (Note 16)	135	174	899	267
Other	6	4	7	22
Exploration expenses (Note 3)	28	23	101	80
Proceeds from sale of accounts receivable (Note 9)	-	-	80	399
(Increase) decrease in non-cash working capital related to operating activities	5	266	(289)	347
Cash flow from operating activities	1,068	1,135	2,642	3,368
Investing activities				
Expenditures on property, plant and equipment and exploration (Notes 3 and 10)	(770)	(752)	(2,725)	(3,019)
Proceeds from sale of assets	8	5	29	37
Increase in deferred charges and other assets	(14)	(7)	(55)	(21)
Acquisition of Prima Energy Corporation (Note 11)	-	(644)	-	(644)
(Increase) decrease in non-cash working capital and other related to investing activities	(8)	24	202	20
	(784)	(1,374)	(2,549)	(3,627)
Financing activities				
Increase (decrease) in short-term notes payable	(24)	(57)	(303)	229
Proceeds from issue of long-term debt (Note 12)	-	533	762	533
Repayment of long-term debt	(2)	(2)	(5)	(298)
Proceeds from issue of common shares (Note 13)	16	7	61	31
Purchase of common shares (Note 13)	(115)	(278)	(257)	(288)
Dividends on common shares	(52)	(40)	(130)	(120)
(Increase) decrease in non-cash working capital related to financing activities	1	-	-	(18)
	(176)	163	128	69
Increase (decrease) in cash and cash equivalents	108	(76)	221	(190)
Cash and cash equivalents at beginning of period	283	521	170	635
Cash and cash equivalents at end of period	$ 391	$ 445	$ 391	$ 445

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET *(unaudited)*
As at September 30, 2005
(millions of Canadian dollars)

	September 30, 2005	December 31, 2004
Assets		
Current assets		
Cash and cash equivalents	$ 391	$ 170
Accounts receivable (Note 9)	1,700	1,254
Inventories	554	549
Prepaid expenses	44	13
	2,689	1,986
Property, plant and equipment, net	15,865	14,783
Goodwill	864	986
Deferred charges and other assets	405	345
	$ 19,823	$ 18,100
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 2,392	$ 2,223
Income taxes payable	376	370
Short-term notes payable	-	299
Current portion of long-term debt	7	6
	2,775	2,898
Long-term debt (Note 12)	2,896	2,275
Other liabilities	1,843	646
Asset retirement obligations	833	834
Future income taxes	2,451	2,708
Shareholders’ equity		
Common shares (Note 13)	1,364	1,314
Contributed surplus (Note 13)	1,504	1,743
Retained earnings	6,355	5,408
Foreign currency translation adjustment	(198)	274
	9,025	8,739
	$ 19,823	$ 18,100

See accompanying Notes to Consolidated Financial Statements

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

1. SEGMENTED INFORMATION
Three months ended September 30,

	North American Natural Gas		East Coast Oil		Oil Sands		International		Downstream		Shared Services		Consolidated	
	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Revenue														
Sales to customers	$ 532	$ 434	$ 321	$ 212	$ 261	$ 121	$ 728	$ 569	$3,122	$2,452	$ -	$ -	$ 4,964	$ 3,788
Investment and other income	-		(3)	(1)		-	(133)	(173)	19		(6)		(119)	(166)
Inter-segment sales	83	53					-	-	3	4	-	-		
		1			4					3		4		
Segmented revenue			103	171	202	147			3,144	2,459	(6)	4	4,845	3,622
Expenses	615	488	421	382	467	268	595	396						
Crude oil and product purchases	121	88	-	-	163	75	-	-	2,188	1,643	(3)	1	2,469	1,807
Inter-segment transactions					21	11	-	-	368	360	-	-		
Operating, marketing and general		98	36	32		90					53	16	780	664
Exploration	1 109 34	2 27	1	2	119	1	109 20	106 21	354	322			54	49
Depreciation, depletion and amortization			-	-	-		117	116	-	-	- (1)	- -	369	352
Unrealized gain on translation of foreign currency denominated long-term debt	91	83	62	68	40	16			60	69	(90)	(67)	(90)	(67)
Interest Upstream	-										39	33	39	33
	-	-	- 99	-	-	-	-	-	- 2,970	- 2,394	(2)	(17)	3,621	2,838
	356	298	-	102	343	193	246	243	-	-				
Earnings (loss) before income taxes	259					75				65	(4)	21	1,224	784
Provision for income taxes		190	322	280	124		349	153	174					
Current			106		(5)	(8)	361	199			(21)	(14)	612	412
Future	75 28	96	(2)	91 (1)	44	32			96	48	4	11	(2)	(38)
	103	(23)	104				(52)309	(32)167	(24)	(25)	(17)	(3)	610	374
Net earnings (loss)	$ 156	$73 117	$ 218	$90 190	$39 85	$84 51	$ 40	$ (14)	$72 102	$83 42	$ 13	$ 24	$ 614	$ 410
Expenditures on property, plant and equipment and exploration	$ 151	$ 166	$ 98	$ 76	$ 117	$ 100	$ 147	$ 193	$ 255	$ 215	$ 2	$ 2	$ 770 (1)	$ 752 (1)
Cash flow from operating activities	$ 247	$ 218	$ 395	$ 285	$ 110	$ 93	$ 208	$ 217	$ 66	$ 159	$ 42	$ 163	$ 1,068	$ 1,135

(1) Expenditures include capitalized interest in the amount of $10 million for the three months ended September 30, 2005 ($8 million for the three months ended September 30, 2004).

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

1. SEGMENTED INFORMATION
Nine months ended September 30,

	North American Natural Gas		East Coast Oil		Oil Sands		International		Downstream		Shared Services		Consolidated	
	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Revenue														
Sales to customers	$1,415	$1,299	$ 917	$ 716	$ 558	$ 301	$1,982	$1,653	$8,258	$6,911	$ -	$ -	$13,130	$10,880
Investment and other income	1	2	(3)	(1)	4	-	(871)	(244)		8	(21)		(843)	(220)
Inter-segment sales							-	-	47 10	9	-	15 -		
Segmented revenue	232 1,648	151 1,452	279 1,193	412 1,127	483 1,045	402 703	1,111	1,409	8,315	6,928	(21)	15	12,287	10,660
Expenses														
Crude oil and product purchases	322	274	-	-	405	200	-	-	5,693	4,468	(3)	4	6,417	4,946
Inter-segment transactions					53	33	-	-	942	932	-	-		
Operating, marketing and general				93					1,026			46	2,234	1,988
Exploration	5 310	5 276	4 116 -	4 2	318	262	345	336	-	975 -	119 -	-	194	159
Depreciation, depletion and amortization	98	75			31 90	10 40	65	72			-	1	1,066	1,050
Unrealized gain on translation of foreign currency denominated long-term debt Upstream	275	232	198	210			338	362	165	205	(95)	(25)	(95)	(25)
Interest											112	108	112	108
	- 1,010	-	-	-	-	-	-	-	- 7,826	- 6,580			9,928	8,226
	-	- 862	- 318	- 309	- 897	- 545	- 748	- 770	-	-	133	134		
Earnings (loss) before income taxes	638										(154)	(119)	2,359	2,434
Provision for income taxes		590	875	818	148	158	363	639	489	348				
Current					(27)	(35)					(74)	(53)	1,504	1,231
Future	223	278 (57)	278 2	254 6			837 (259)	597 (90)	267	190	3	9	(222)	(113)
	39				75 48	83 48			(82)	(64)	(71)	(44)	1,282	1,118
Net earnings (loss)	262 $ 376	221 $ 369	280 $ 595	260 $ 558	$ 100	$ 110	578 $ (215)	507 $ 132	185 $ 304	126 $ 222	$ (83)	$ (75)	$ 1,077	$ 1,316
Expenditures on property, plant and equipment and exploration	$ 531	$ 471	$ 225	$ 197	$ 663	$ 265	$ 567	$1,551	$ 733	$ 531	$ 6	$ 4	$ 2,725 (1)	$ 3,019 (1)
Cash flow from operating activities	$ 737	$ 668	$ 837	$ 775	$ 220	$ 243	$ 631	$ 802	$ 339	$ 686	$ (122)	$ 194	$ 2,642	$ 3,368

(1) Expenditures include capitalized interest in the amount of $27 million for the nine months ended September 30, 2005 ($13 million for the nine months ended September 30, 2004).

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

2. BASIS OF PRESENTATION

The note disclosure requirements for annual Consolidated Financial Statements provide additional disclosure to that required for interim Consolidated Financial Statements. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements included in the Company's 2004 Annual Report. The interim Consolidated Financial Statements are presented in accordance with Canadian generally accepted accounting principles and follow the accounting policies summarized in the notes to the annual Consolidated Financial Statements except for the change described in Note 3.

3. CHANGES IN ACCOUNTING POLICIES

Statement of Cash Flows

Effective January 1, 2005, the Company changed the presentation of cash flow in the Consolidated Statement of Cash Flows pursuant to recent interpretations from the United States Securities and Exchange Commission. Previously, all exploration expenses were classified as investing activities. With the change, general and administrative and geological and geophysical exploration expenses are treated as a reduction of cash flow from operating activities. All prior periods have been restated to reflect this change. The change results in a decrease in cash flow from operating activities and an increase in cash flow from investing activities by $26 million and $93 million for the three and nine months ended September 30, 2005, respectively ($26 million and $79 million for the three and nine months ended September 30, 2004).

4. STOCK DIVIDEND

In July 2005, the Company effected a two-for-one stock-split in the form of a stock dividend. Common shareholders of record at the close of business on September 3, 2005 received one additional common share for each common share held. Information related to common shares, stock options and performance share units has been restated to reflect the above.

5. INVESTMENT AND OTHER INCOME

Investment and other income includes net losses on derivative contracts (see Note 16) of $125 million and $884 million for the three and nine months ended September 30, 2005, respectively ($180 million and $270 million for the three and nine months ended September 30, 2004) and net gains on disposal of assets of $9 million and $23 million for the three and nine months ended September 30, 2005, respectively ($2 million and $12 million for the three and nine months ended September 30, 2004).

6. ASSET WRITE-DOWNS

Following a review of its Eastern Canada refining and supply operations, Petro-Canada announced in September 2003 it would cease the Oakville refining operations and expand the existing terminalling facilities. The total charge to earnings related to the shutdown, which occurred in April 2005, was approximately $200 million after-tax. The following expenses have been recorded in the Downstream segment:

	Three months ended September 30,				Nine months ended September 30,			
	2005		2004		2005		2004	
	Pre-Tax	After-Tax	Pre-Tax	After-Tax	Pre-Tax	After-Tax	Pre-Tax	After-Tax
Operating, marketing and general expenses (de-commissioning and employee related costs)	$ (5)	$ (3)	$ -	$ -	$ (4)	$ (2)	$ 2	$ 1
Depreciation and amortization expenses (asset write-downs and increased depreciation)	-	-	15	9	1	-	55	34
	$ (5)	$ (3)	$ 15	$ 9	$ (3)	$ (2)	$ 57	$ 35

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

7. INCOME TAXES

The provision for future income taxes for the nine months ended September 30, 2004 was reduced by $13 million due to the substantively enacted reduction in provincial income tax rates. The adjustment was allocated to the segments as a decrease (increase) to the tax provision as follows: North American Natural Gas - $7 million, East Coast Oil - $3 million, Oil Sands - $2 million, Downstream - $2 million and Shared Services - $(1) million.

8. EARNINGS PER SHARE

The following table provides the common shares used in calculating net earnings per common share:

	Three months ended September 30,		Nine months ended September 30,	
(millions)	2005	2004	2005	2004
Weighted-average number of common shares outstanding - basic	518.1	531.7	519.2	532.0
Effect of dilutive stock options	7.3	7.1	7.0	7.0
Weighted-average number of common shares outstanding - diluted	525.4	538.8	526.2	539.0

9. SECURITIZATION PROGRAM

During 2004, the Company entered into a securitization program, expiring in 2009, to sell an undivided interest of eligible accounts receivable to a third party, on a revolving and fully serviced basis.

In March 2005, Petro-Canada increased the limit to sell eligible accounts receivable under the program from $400 million to $500 million. During the nine months ended September 30, 2005, the Company sold an additional $80 million of outstanding receivables for net proceeds of $80 million.

As at September 30, 2005, $480 million of outstanding accounts receivable had been sold under the program.

10. FORT HILLS OIL SANDS MINING PROJECT

In June 2005, the Company acquired a 60% interest in the Fort Hills oil sands mining project which was previously wholly owned by UTS Energy Corporation (UTS). To pay for the investment, Petro-Canada will fund 75% of UTS' share of the next $1 billion of development capital, or $300 million.

Expenditures on property, plant and equipment and exploration in the Consolidated Statement of Cash Flows include the discounted value of the acquisition cost amounting to $269 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

11. ACQUISITION OF PRIMA ENERGY CORPORATION

On July 28, 2004, Petro-Canada acquired all of the common shares of Prima Energy Corporation, an oil and gas company with operations in the U.S. Rockies, for a total acquisition cost of $644 million, net of cash acquired. The results of operations were included in the Consolidated Financial Statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

Property, plant and equipment	$	688
Goodwill		193
Current assets, excluding cash of $74 million		36
Deferred charges and other assets		2
Total assets acquired		919
Current liabilities		41
Future income taxes		217
Asset retirement obligations and other liabilities		17
Total liabilities assumed		275
Net assets acquired	$	644

Goodwill, which is not tax deductible, was assigned to Petro-Canada's North American Natural Gas business segment.

12. LONG-TERM DEBT

	Maturity	September 30, 2005	
Debentures and notes			
5.95% unsecured senior notes ($600 million US) [1]	2035	$	697
5.35% unsecured senior notes ($300 million US)	2033		348
7.00% unsecured debentures ($250 million US)	2028		290
7.875% unsecured debentures ($275 million US)	2026		320
9.25% unsecured debentures ($300 million US)	2021		348
5.00% unsecured senior notes ($400 million US)	2014		465
4.00% unsecured senior notes ($300 million US)	2013		348
Capital leases	2007-2017		78
Retail licensee trust loans	2012-2014		9
			2,903
Current portion			(7)
		$	2,896

(1) In May 2005, the Company issued $600 million US 5.95% notes due May 15, 2035. The proceeds were used primarily to repay existing short-term notes payable.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

13. SHAREHOLDERS' EQUITY

Changes in common shares and contributed surplus were as follows:

	Shares	Amount	Contributed Surplus
Balance at January 1, 2005	519,928,022	$ 1,314	$ 1,743
Issued under employee stock option and share purchase plans	3,347,132	61	-
Repurchased under normal course issuer bid	(6,333,400)	(16)	(241)
Stock-based compensation	-	5	2
Balance at September 30, 2005	516,941,754	$ 1,364	$ 1,504

In June 2005, the Company renewed its normal course issuer bid to repurchase up to 26 million of its common shares, on a restated basis (Note 4), during the period from June 22, 2005 to June 21, 2006, subject to certain conditions. The Company purchased 2,400,000 shares at a cost of $115 million and 6,333,400 shares at a cost of $257 million during the three and nine months ended September 30, 2005, respectively (8,597,788 shares at a cost of $278 million and 8,929,788 shares at a cost of $288 million during the three and nine months ended September 30, 2004). The excess of the purchase price over the carrying amount of the shares purchased, which totaled $109 million and $241 million for the three and nine months ended September 30, 2005, respectively, was recorded as a reduction of contributed surplus.

14. STOCK-BASED COMPENSATION

Changes in the number of outstanding stock options and performance share units (PSUs) were as follows:

	Stock Options		PSUs
	Number	Weighted-Average Exercise Price *(dollars)*	Number
Balance at January 1, 2005	18,074,698	$ 21	565,860
Granted	4,004,800	34	640,556
Exercised	(3,347,132)	18	-
Cancelled	(297,449)	29	(47,762)
Balance at September 30, 2005	18,434,917	$ 24	1,158,654

The total stock-based compensation expense recorded was $49 million and $86 million during the three and nine months ended September 30, 2005, respectively ($6 million and $11 million for the three and nine months ended September 30, 2004).

Compensation expense has not been recorded for stock options issued prior to 2003. The following table presents the pro forma net earnings and the pro forma earnings per share computed assuming the fair value based accounting method had been used to account for the compensation cost of stock options granted in 2002.

	Three months ended September 30,					
	2005	2004	2005		2004	
	Net earnings		Earnings per share *(dollars)*			
			Basic	Diluted	Basic	Diluted
Net earnings as reported	$ 614	$ 410	$ 1.19	$ 1.17	$ 0.77	$ 0.76
Pro forma adjustment	2	2	0.01	0.01	-	-
Pro forma net earnings	$ 612	$ 408	$ 1.18	$ 1.16	$ 0.77	$ 0.76

	Nine months ended September 30,					
	2005	2004	2005		2004	
	Net earnings		Earnings per share *(dollars)*			
			Basic	Diluted	Basic	Diluted
Net earnings as reported	$ 1,077	$ 1,316	$ 2.07	$ 2.05	$ 2.47	$ 2.44
Pro forma adjustment	6	7	0.01	0.01	0.01	0.01
Pro forma net earnings	$ 1,071	$ 1,309	$ 2.06	$ 2.04	$ 2.46	$ 2.43

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

15. 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 September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Pension Plans:				
Defined benefit plans				
Employer current service cost	$ 8	$ 6	$ 24	$ 19
Interest cost	21	20	63	60
Expected return on plan assets	(22)	(19)	(65)	(57)
Amortization of transitional asset	(1)	(1)	(3)	(3)
Amortization of net actuarial losses	9	8	26	23
	15	14	45	42
Defined contribution plan	4	3	11	9
	$ 19	$ 17	$ 56	$ 51
Other post-retirement plans:				
Employer current service cost	$ 1	$ 1	$ 3	$ 3
Interest cost	3	3	9	9
Amortization of transitional obligation	-	1	1	3
	$ 4	$ 5	$ 13	$ 15

The Company expects to contribute $95 million to its pension plans in 2005. As at September 30, 2005, $70 million in contributions have been made.

16. FINANCIAL INSTRUMENTS AND DERIVATIVES

Investment and other income includes unrealized losses on the outstanding derivative contracts associated with the 2004 acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea. Unrealized losses relating to these contracts amounted to $135 million and $899 million for the three and nine months ended September 30, 2005, respectively ($174 million and $267 million for the three and nine months ended September 30, 2004).

Unrealized losses on all derivative contracts have decreased investment and other income by $133 million and $890 million for the three and nine months ended September 30, 2005, respectively ($167 million and $266 million for the three and nine months ended September 30, 2004). As at September 30, 2005, accounts receivable and other liabilities have been increased by $13 million and $1,232 million, respectively as a result of unrealized mark-to-market amounts on derivative contracts.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

17. VARIABLE INTEREST ENTITIES

Accounting Guideline 15 (AcG 15), *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the variable interest entity's activities, or is entitled to receive a majority of the variable interest entity's residual returns, or both. The Company determined that certain retail licensee agreements would constitute VIEs, even though the Company has no ownership in these entities. The Company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of these retail licensee arrangements, the Company has provided loan guarantees. Management is of the opinion that the Company's maximum exposure to loss from these arrangements would not be material.