Company Registration No. 3084447

Petro-Canada Energy North Sea Limited

Annual Report and Financial Statements

31 December 2008

31-10-09
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Petro-Canada Energy North Sea Limited

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Petro-Canada Energy North Sea Limited

Directors' report

The directors present their annual report and the audited accounts for the year ended 31 December 2008. The directors' report has been prepared in accordance with the special provisions relating to small companies under section 246 (4) of the Companies Act 1985.

Principal activities

The Company has no trading activities and only generates income from a loan to its parent company, Petro-Canada UK Limited.

Business review

As this Company sold its main asset to Petro-Canada UK Limited on 1 January 2005, there have been no transactions other than inter-company interest receipts on two loans and the related tax thereon. At the balance sheet date, the amount of £166.67 million plus accrued interest remains outstanding on such loans.

Future developments

The Company's intention is to repay the loan in five equal annual instalments. A repayment was made in January 2009 and the next repayment is due in January 2010.

Results and dividends

The profit for the year after taxation amounted to £10.8 million (2007 – £4.8 million profit).

The Company has paid dividends of £40.5 million (2007 - £nil million).

Directors and their interests

The directors who served during the year and subsequently were:

P. S. Kallos	(British)	
N. A. Maden	(British)	
G. V. Lyon	(British)	Resigned 31 August 2008
G. J. Carrick	(Canadian)	
H. J. Wesley	(British)	Resigned 6 October 2009

The directors who held office at the end of the financial year do not have any interests in the shares of the Company or any other UK company, nor received any remuneration from the Company.

Going Concern

The Company's business activities, together with the factors likely to affect its future development and performance, are set out above.

The Company relies upon its parent, Petro-Canada UK Limited, to repay the intercompany loan. The directors of the Company (being also directors of Petro-Canada UK Limited) are satisfied that the Company's counterparty is in a strong financial position and that these receivables are fully recoverable. The directors are not aware of any reason to believe that the acquisition of the ultimate parent company by Suncor Inc. (See Note 12) will have any adverse material impact on their ability to continue to meet their obligations as they fall due for the foreseeable future. As a consequence, the directors believe that the Company is well placed to manage its business risks successfully despite the uncertain economic outlook.

After making enquiries, the directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis in preparing the annual report and financial statements.

Petro-Canada Energy North Sea Limited

Directors' report (continued)

Charitable and political contributions

The Company did not make any charitable or political contributions.

Auditors

Each of the persons who is a director at the date of approval of this report confirms that:

(1) so far as the director is aware, there is no relevant audit information of which the Company's auditors are unaware; and

(2) the director has taken all the steps that he/she ought to have taken as a director in order to make himself/herself aware of any relevant audit information and to establish that the Company's auditors are aware of that information.

This confirmation is given and should be interpreted in accordance with the provisions of s234ZA of the Companies Act 1985.

By order of the Board

P. S. Kallos
Director

1 London Bridge
London
SE1 9BG

29 October 2009

Petro-Canada Energy North Sea Limited

Statement of directors' responsibilities

The directors are responsible for preparing the Annual Report including the financial statements. The directors have chosen to prepare the financial statements for the Company in accordance with United Kingdom Generally Accepted Accounting Practice (UK GAAP).

Company law requires the directors to prepare such financial statements for each financial year which give a true and fair view, in accordance with UK GAAP, of the state of affairs of the Company and of the profit or loss of the Company for that period and comply with UK GAAP and the Companies Act 1985. In preparing those financial statements, the directors are required to:

- select suitable accounting policies and then apply them consistently;
- make judgements and estimates that are reasonable and prudent;
- state whether applicable accounting standards have been followed; and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

The directors are responsible for keeping proper accounting records which disclose with reasonable accuracy at any time the financial position of the Company and enable them to ensure that the financial statements comply with the Companies Act 1985. They are also responsible for safeguarding the assets of the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Petro-Canada Energy North Sea Limited

Statement of Corporate responsibility

Petro-Canada world-wide is deeply committed to responsible business practices. This commitment extends to corporate governance practices, environment, health and safety performance and involvement in communities where our employees live and work. To review our performance in these areas in more detail, we publish an annual Report to the Community. You can review the report on our website www.petro-canada.com.

Corporate Governance

Petro-Canada strives to maintain the highest standards of corporate governance, with a focus on a strong and diligent Board of Directors and transparency for shareholders. Petro-Canada has solid governance and disclosure practices, and an ethical corporate culture.

Environment, Health and Safety

Strong environment, health and safety performance is fundamental to our business as an energy company. Underpinning our drive to consistently improve performance is the Total Loss Management system, which provides clear management expectations, details employee responsibilities and serves as a mechanism for ongoing stewardship and continuous improvement through a programme of regularly scheduled facility audits. We also use a Life-Cycle Value Assessment tool to help us identify opportunities to improve technical designs, reduce environmental impacts and reduce costs.

The safety and well-being of our employees and those working on our behalf is an absolute business priority for Petro-Canada. To support them, Petro-Canada provides a wide range of programmes, training and policies related to employee well-being. We believe that all workplace injuries and illnesses are preventable and that a "Zero Harm" workplace is possible and is our goal.

Community investment

As a responsible corporate citizen, Petro-Canada works hard to develop relationships of trust and respect, and contribute to community well-being in the areas where we operate.

Petro-Canada Energy North Sea Limited

Independent auditors' report to the members of Petro-Canada Energy North Sea Limited

We have audited the financial statements of Petro-Canada Energy North Sea Limited for the year ended 31 December 2008 which comprise the Profit and Loss Account, the Balance Sheet, and the related notes 1 to 12. These financial statements have been prepared under the accounting policies set out therein.

This report is made solely to the company's members, as a body, in accordance with section 235 of the Companies Act 1985. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditors' report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditors

The directors' responsibilities for preparing the Annual Report and the financial statements in accordance with applicable law and United Kingdom Accounting Standards (United Kingdom Generally Accepted Accounting Practice) are set out in the Statement of Directors' Responsibilities.

Our responsibility is to audit the financial statements in accordance with relevant legal and regulatory requirements and International Standards on Auditing (UK and Ireland).

We report to you our opinion as to whether the financial statements give a true and fair view and are properly prepared in accordance with the Companies Act 1985. We also report to you whether in our opinion the information given in the Directors' Report is consistent with the financial statements.

In addition we report to you if, in our opinion, the company has not kept proper accounting records, if we have not received all the information and explanations we require for our audit, or if information specified by law regarding directors' remuneration and other transactions is not disclosed.

We read the other information contained in the Annual Report as defined in the contents page, and consider whether it is consistent with the audited financial statements. We consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the financial statements. Our responsibilities do not extend to any further information outside the Annual Report.

Basis of audit opinion

We conducted our audit in accordance with International Standards on Auditing (UK and Ireland) issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the financial statements. It also includes an assessment of the significant estimates and judgments made by the directors in the preparation of the financial statements, and of whether the accounting policies are appropriate to the company's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion we also evaluated the overall adequacy of the presentation of information in the financial statements.

Opinion

In our opinion:

- the financial statements give a true and fair view, in accordance with United Kingdom Generally Accepted Accounting Practice, of the state of the company's affairs as at 31 December 2008 and of its profit for the year then ended;
- the financial statements have been properly prepared in accordance with the Companies Act 1985; and
- the information given in the Directors' Report is consistent with the financial statements.

Deloitte LLP

Deloitte LLP
Chartered Accountants and Registered Auditors
London, United Kingdom.

29 October 2009

Petro-Canada Energy North Sea Limited

Profit and loss account
Year ended 31 December 2008

	Notes	2008 £million	2007 £million
Interest receivable and similar income	3	**10.2**	11.9
Profit on ordinary activities before taxation		**10.2**	11.9
Tax credit / (charge) on profit on ordinary activities	4	**0.6**	(7.1)
Profit for the financial year		**10.8**	4.8

There are no recognised gains and losses during the year other than the profit for the year. Accordingly, a statement of total recognised gains and losses is not presented.

The Company's results are all derived from continuing activities.

Balance sheet
31 December 2008

	Notes	2008 £million	2007 £million
Current assets			
Debtors			
- due within one year	6	**48.7**	48.3
- due after one year	6	**133.3**	166.7
		182.0	215.0
Creditors: amounts falling due within one year	7	**(2.0)**	(5.3)
Net current assets		**180.0**	209.7
Total assets less current liabilities		**180.0**	209.7
Capital and reserves			
Called up share capital	8	**1.3**	1.3
Share premium account	9	**129.7**	129.7
Profit and loss account	9	**49.0**	78.7
Total shareholders' funds	9	**180.0**	209.7

Company Number 3084447

Approved by the Board of Directors and signed on its behalf on 29 October 2009 by:

P. S. Kallos
Director

Petro-Canada Energy North Sea Limited

Notes to the accounts
Year ended 31 December 2008

1. **Accounting policies**

A summary of the principal accounting policies, all of which have been applied consistently throughout the year and the preceding year, is set out below:

(a) **Basis of accounting**

The accounts are prepared under the historical cost convention and in accordance with applicable United Kingdom accounting standards.

Under the provisions of FRS 1 (Revised 1996) "Cash flow statements", the Company has not presented a cash flow statement because it is a wholly owned subsidiary of Petro-Canada UK Limited which itself is a wholly owned subsidiary of Petro-Canada, incorporated in Canada. The consolidated accounts of Petro-Canada are publicly available.

(b) **Taxation**

UK corporation tax is provided at amounts expected to be paid (or recovered) using the tax rates and laws that have been enacted or substantively enacted by the balance sheet date. Amounts surrendered to or from other group undertakings are paid for in full.

Deferred tax is recognised in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events that result in an obligation to pay more tax in the future or a right to pay less tax in the future have occurred at the balance sheet date. Timing differences are differences between the Company's taxable profits and its results as stated in the accounts that arise from the inclusion of gains and losses in tax assessments in periods different from those in which they are recognised in the accounts.

A net deferred tax asset is regarded as recoverable and therefore recognised only when, on the basis of all available evidence, it can be regarded as more likely than not that there will be suitable taxable profits from which the future reversal of the underlying timing differences can be deducted.

Deferred tax is measured at the average tax rates that are expected to apply in the periods in which the timing differences are expected to reverse, based on tax rates and laws that have been enacted or substantively enacted by the balance sheet date. Deferred tax is measured on a non-discounted basis.

(c) **Foreign currencies**

Transactions in foreign currencies are recorded at the relevant rate of exchange prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies at the balance sheet date are reported at the rates of exchange prevailing at that date. Any gain or loss arising from a change in exchange rates subsequent to the date of the transaction is included as an exchange gain or loss in the profit and loss account.

(d) **Going Concern**

The Company's business activities, together with the factors likely to affect its future development, performance are set out in the Directors' Report.

The Company relies upon its parent, Petro-Canada UK Limited, to repay the intercompany loan. The directors of the Company (being also directors of Petro-Canada UK Limited) are satisfied that the Company's counterparty is in a strong financial position and that these receivables are fully recoverable. The directors are not aware of any reason to believe that the acquisition of the ultimate parent company by Suncor Inc. (See Note 12) will have any adverse material impact on their ability to continue to meet their obligations as they fall due for the foreseeable future. As a consequence, the directors believe that the Company is well placed to manage its business risks successfully despite the uncertain economic outlook.

After making enquiries, the directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis in preparing the annual report and financial statements.

2. Administration costs

The Company had no employees in 2008 (2007 – nil).

The directors received no remuneration for services to the Company during either year.

Two directors exercised stock options in the ultimate parent company during 2008 (2007: two).

Auditors' remuneration

	2008	2007
	£000	£000
The analysis of the auditors' remuneration in respect of the Company is as follows:		
Fees payable to the Company's auditors for the audit of the Company's annual accounts	7	5

There were no fees payable for other services in either year.

3. Interest receivable and similar income

	2008 £million	2007 £million
Interest received and receivable from group undertakings	**10.2**	11.9

Notes to the accounts
Year ended 31 December 2008 (continued)

4. Tax charge on profit on ordinary activities

(a) Analysis of tax charge in the year

	2008 £million	2007 £million
Current tax		
UK corporation tax for current year	**2.9**	3.6
Adjustment in respect of prior years	**(3.5)**	3.5
Total tax (credit) / charge on profit on ordinary activities	**(0.6)**	7.1

(b) Reconciliation of current tax charge in the year

	2008 £million	2007 £million
Profit on ordinary activities before tax	**10.2**	11.9
Tax at 28.5%	**2.9**	3.6
Effects of:		
Adjustment in respect of prior years	**(3.5)**	3.5
Current tax (credit) / charge for the year	**(0.6)**	7.1

There was no deferred tax at either balance sheet date.

5. Dividends paid

The Company paid dividends of £40.5million (2007: £nil) representing £172.64 (2007: £nil) per equity share during the year to its immediate parent company, Petro Canada UK Limited.

Notes to the accounts
Year ended 31 December 2008 (continued)

6. Debtors

	2008 £million	2007 £million
Amounts falling due within one year		
Amounts owed by parent undertaking	**42.6**	44.4
Amounts owed by group undertakings:		
- internal clearing cash account	**6.1**	3.9
	48.7	48.3

To optimise the use of liquid funds, the Company's cash is held within a cash pooling system administered by another company within the group.

	2008 £million	2007 £million
Amounts falling due after one year		
Amounts owed by parent undertaking	**133.3**	166.7

The amounts owed by parent undertaking represents an unsecured loan of £200 million, and interest thereon, which was issued on 18 January 2005 and is expected to be fully repaid in six equal annual instalments commencing on January 2008. The loan carries interest at 5.8125% to be received annually in arrears commencing on the first anniversary of the date of issue.

7. Creditors falling due within one year

	2008 £million	2007 £million
Sundry creditors	**0.5**	0.5
Corporation tax	**1.5**	4.8
	2.0	5.3

8. Called up share capital

	2008 £'000	2007 £'000
Authorised:		
300,000 Class A ordinary shares of US$10 each	**1,634**	1,634
10,000 Class B ordinary shares of £1 each	**10**	10
	1,644	1,644
Called up, allotted and fully paid		
234,588 (2007– 234,588) Class A ordinary shares of US$10 each	**1,277**	1,277
1,000 Class B ordinary shares of £1 each	**1**	1
	1,278	1,278

Class B ordinary shares carry full voting rights; however, they carry no right to receive dividends from the Company and their economic worth is limited to the nominal value of the shares.

9. Reconciliation of movement in shareholders' funds

	Share capital £million	Share premium £million	Profit and loss account £million	Total shareholders' funds £million
At 1 January 2008	1.3	129.7	78.7	209.7
Profit for the year	-	-	10.8	10.8
Dividend	-	-	(40.5)	(40.5)
At 31 December 2008	1.3	129.7	49.0	180.0

10. Related party transactions

The Company has taken advantage of the exemption available under Financial Reporting Standard 8 "Related Party Disclosures" and has not disclosed details of transactions with other group undertakings as it is a wholly owned subsidiary of Petro-Canada UK Limited which itself is a wholly owned subsidiary of Petro-Canada. The consolidated accounts of Petro-Canada are publicly available.

11. Ultimate parent company

Petro-Canada UK Limited is the immediate parent company. The ultimate parent company and controlling entity at 31 December 2008 was Petro-Canada, a company incorporated in Canada. The consolidated accounts of the Petro-Canada Group, the smallest and largest to include the accounts of the Company, are available from Petro-Canada at 150 – 6th Avenue SW, Calgary, Alberta, Canada T2P 3ES.

12. Post Balance Sheet Event

On 23 March 2009, Petro-Canada announced plans to merge with Suncor Inc, a company incorporated in Canada. Petro-Canada and Suncor shareholders have approved the merger, as have the Court of Queen's Bench of Alberta and the Competition Bureau. The merger with Petro-Canada and Suncor is effective from 1 August 2009. The directors do not believe that this will impact the ability of the Company to continue as a going concern.

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Cover design: The Design Centre of Canada; Inside: Platinum Creative Solutions Inc.

This report was printed on paper that is acid-free and recyclable. Inks are based on linseed oil and contain no heavy metals. The printing process was alcohol-free. Volatile organic compounds associated with printing were reduced by 50% to 75% from the levels that would have been produced using traditional inks and processes.

Legal Notice – Forward-Looking Information

This annual 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. Forward-looking information in this annual report includes references to:

- 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
- anticipated construction and repair activities
- anticipated 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
- anticipated retail throughputs
- anticipated pre-production and operating costs
- reserves and resources estimates
- future 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)
- the impact and cost of compliance with existing and potential environmental regulations
- future regulatory approvals
- expected rates of return

Such forward-looking information is based on a number of assumptions and analysis made by the Company. These assumptions and analysis are described in greater detail throughout this annual report and include, without limitation, assumptions with respect to future commodity prices, the state of the economy, required capital expenditures, levels of cash flow, regulatory requirements, industry capacity, the results of exploration and development drilling and the ability of suppliers to meet commitments.

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

- changes in 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
- changes in general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and natural gas prices
- changes in 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). See also "Risk Management – Risks Relating to Petro-Canada's Business" in this annual report for a discussion of factors that could impact Petro-Canada's operations or results.

Readers are cautioned that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this annual report is made as of February 23, 2009 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 annual 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 annual 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 annual report does not meet the SEC guidelines for SEC filings. To disclose reserves in SEC filings, oil and natural gas companies must prove they are economically and legally producible under existing economic and operating conditions. Note that when the term barrels of oil equivalent (boe) is used in this annual 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 Oil Sands 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 and 3C for Contingent Resources, and low, best and high estimates for Prospective Resources, Petro-Canada will only refer to the unrisked 2C for Contingent Resources and the partially risked best estimate for Prospective Resources when referencing resources in this annual report. Estimates of resources in this annual report include contingent resources that have not been adjusted for risk based on the chance of development and partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development. Such estimates are not estimates of volumes that may be recovered and actual recovery is likely to be less and may be substantially less or zero. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Canadian Oil Sands represents approximately 68% 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, unrisked Contingent Resources are approximately 70% of the Company's total resources and partially risked Prospective Resources are approximately 30% 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 reserves categories, all projects must have an economic depletion plan and may require:

- additional delineation drilling and/or new technology for unrisked Contingent Resources
- exploration success with respect to partially risked Prospective Resources
- project sanction and regulatory approvals

Reserves and resources information contained in this annual report is as at December 31, 2008.

About Petro-Canada

Petro-Canada (the Company) is one of Canada's largest oil and gas companies, operating in both the upstream and the downstream sectors of the industry in Canada and internationally. The Company creates value by responsibly developing energy resources and providing world class petroleum products and services. Petro-Canada is proud to be a National Partner to the Vancouver 2010 Olympic and Paralympic Winter Games. Petro-Canada's common shares trade on the Toronto Stock Exchange (TSX) under the symbol PCA and on the New York Stock Exchange (NYSE) under the symbol PCZ.

With a market capitalization of approximately $13.6 billion[1], Petro-Canada is a mid-sized energy company. Our roots are in Canada, a country rich in resources and part of the large and growing North American market.

In 2008, Petro-Canada continued to execute its business strategy to focus on operational execution, resulting in the delivery of base business targets, and to advance our major growth projects for future long-term profitability.

This annual report provides details of Petro-Canada's operational and financial capabilities. The Report to the Community, which the Company will publish mid-2009, will elaborate on Petro-Canada's commitment to corporate responsibility objectives and performance.

Financial and Operating Highlights

	2008	2007	2006	2005	2004
Net earnings from continuing operations *($ millions)*	**3,134**	2,733	1,588	1,693	1,698
Cash flow from continuing operating activities *($ millions)*[1]	**6,522**	3,339	3,608	3,783	3,928
Expenditures on property, plant and equipment and exploration from continuing operations *($ millions)*	**6,344**	3,988	3,434	3,560	3,893
Debt-to-debt plus equity *(%)*[2]	**23.5**	22.5	21.7	23.5	22.8
Debt-to-cash flow from continuing operating activities *(times)*	**0.7**	1.0	0.8	0.8	0.8
Return on capital employed *(%)*[2]	**18.6**	19.8	14.3	16.0	17.5
Upstream proved reserves before royalties *(millions of barrels of oil equivalent – MMboe)*[3]	**1,286**	1,315	1,274	1,232	1,213

1 Cash flow from continuing operating activities in 2007 was reduced by the payment of $1,145 million after-tax to settle the hedged portion of Buzzard production.
2 Includes results from discontinued operations.
3 The reporting of working interest reserves before royalties, MMboe and combining oil and gas and oil sands mining activities together does not conform to SEC standards.

1 As of February 27, 2009.

Q&A with the President

At the beginning of 2008, we set two key priorities for Petro-Canada: to meet base business targets and to advance our major growth projects. I want to take this opportunity to explain how the Company performed against these priorities, and to share with you why I believe Petro-Canada has the *strength to deliver*.

How reliable were Petro-Canada's operations in 2008?

We had solid results in 2008, particularly at Terra Nova and MacKay River, with both facilities running at 90% reliability or better. At MacKay River, we exited the year at nameplate capacity of about 30,000 barrels/day. Our other operated facilities also had excellent reliability, including our natural gas plants, lubricants plant and the Montreal refinery. The Edmonton refinery had some challenges, including an unplanned outage in August and a small fire in late January 2009 after having a stellar run through four to five years of continuous construction; all in all, a very good year that resulted in our production coming in at the high end of our guidance range.

What about safety performance in 2008?

Our total recordable injury frequency improved over 2007 and was again among the industry's best. But as long as we continue to have incidents, there is still room to improve. We're continuing to look for ways to reduce injuries, particularly among our contractors. We remain committed to our goal of Zero-Harm.

What progress did Petro-Canada make on its growth projects in 2008?

We achieved many of our planned milestones, including completing construction of the Edmonton refinery conversion project. We also made a final investment decision on the Syria Ebla gas development and it's on target for a 2010 startup. In Libya, we signed agreements on attractive terms for the Exploration and Production Sharing Agreements, adding significantly to our reserves position. At Fort Hills, our front-end engineering and design work is essentially complete. However, escalating costs and the collapse of the financial markets impacted the project. We are looking for ways to reduce these costs, while working with the Alberta government to extend the mine lease. Fort Hills is a quality initiative and will proceed when the time is right.

How strong is Petro-Canada's financial position given the economic downturn and lower commodity prices?

We've always been financially conservative and this has paid off. In mid-2008, we shored up our balance sheet with a substantial debt issue. We entered 2009 with a year-end cash balance of $1.4 billion, and $4.7 billion in unused credit, ***leading*** our Canadian peers when it comes to liquidity. As well, the two metrics used to measure our financial strength (the debt-to-debt plus equity and debt-to-cash flow ratios) are well below our long-term ranges.

What is Petro-Canada's financial strategy to manage through the market uncertainty?

In 2009, we have a planned capital program of $4 billion, down significantly from the $6 to $7 billion range we were looking at for 2009 a year ago. We're prioritizing our capital spending so that no matter how the year unfolds, we can fund most of our capital program from cash flow, cash and, if necessary, a drawdown of available credit facilities. With a strong balance sheet, low debt ratios and diverse businesses able to generate stable cash flows, we're in a great financial position for the times.

How are low commodity prices expected to impact Petro-Canada's business?

We are following the business environment and financial markets closely to manage within our financial means. One of the strengths of our diverse asset base is that we can generate good cash flow even at low oil prices. In our upstream business, 80% of our production will generate positive cash flow at prices well below what we've seen so far this year. Our East Coast and North Sea assets have positive cash flows at crude oil prices of $10/bbl or less.

What cost reductions are management contemplating for Petro-Canada in 2009?

As our number one priority is to focus on operational execution in our base business, we're looking at all our discretionary expenses to reduce spending and lower our overall cost structure across the organization. We are doing this without compromising safety or reliability. We are also appropriately pacing our growth projects for the times, looking for ways to reduce capital costs and improve project economics.

How has the downturn impacted Petro-Canada's suite of growth projects?

We are pacing our growth projects through these challenging times to maintain growth in shareholder value. We intend to advance our three Board of Directors-approved projects as originally planned. These are our Libya Exploration and Production Sharing Agreements, the North Amethyst portion of the White Rose Extensions and our Syria Ebla gas development. For our three unsanctioned projects (Fort Hills, the MacKay River expansion and the Montreal coker), we're waiting to see a recovery in commodity prices and financial markets before moving ahead. In the meantime, we're working to reduce project costs and execution risk.

Is Petro-Canada actively pursuing mergers and/or acquisitions?

Petro-Canada has a strong liquidity position and our focus in 2009 is to preserve our capital. However, we do have some financial flexibility to take advantage of opportunities that would complement our existing assets.

What is management's approach to return cash to shareholders in 2009?

With respect to our use of cash in 2009, our first priority is to fund long-term growth projects. Our second priority is to return cash to shareholders in the form of dividends or share buyback programs. Over the past few years, we have been able to do both, thanks to strong operations and a robust business environment. In 2009, we expect to use most of our free cash to fund operations and projects, so share buybacks will likely not come into play. Paying dividends is a way we return sustainable and growing cash directly to shareholders, a long-term commitment that must be preserved. In that regard, we raised our dividend last July by 54% to $0.20 per share each quarter.

Why do you think Petro-Canada's stock price has underperformed that of its peers?

I believe this is largely due to our strategy of being focused on consistently creating shareholder value over time. Increasingly, equity investors are becoming more short-term oriented, moving in and out of stocks in search of short-term gains. Because we invest in large, long-life projects, our growth tends to come in stages. We are in this business for the long run and are well positioned to succeed in both good and tough economic times. The excellent position we're in during the current circumstances is a good illustration of that.

One specific issue that impacted shareholder sentiment in 2008 was the extraordinary run-up in costs for the Fort Hills project, resulting in one of our key growth projects becoming uneconomic. However, we're addressing that by moving from a schedule-driven to a cost-driven project focus, and taking advantage of the current softening in the construction market to bring capital and operating costs back down.

What is your response to those in the investment community critical of Petro-Canada's strategy?

We are always open to dialogue with existing and prospective shareholders about the Company's strategy and plans. We share their objective of creating long-term shareholder value.

I remain confident that Petro-Canada has the right strategy and plan in place. Our strategy positions the Company well to weather this tough business environment, because it maintains our financial strength and preserves our growth opportunities.

How is management keeping employees engaged during these uncertain times?

Employees are our most valuable resource. Over the years, we have enhanced and increased our focus on leadership development and internal communications to keep employees engaged and up to date on Petro-Canada. We have accelerated development for some strong performers and facilitated face-to-face and online discussions between leaders and their teams. Employees actively participate in many of these discussions.

What is your perspective on the debate between energy development and environmental impact, particularly related to the oil sands?

We recognize both energy development and environmental protection are integral to our success. The oil sands, in particular, play a big role in our future. This supply source makes up a significant portion of global energy supply from non state-controlled countries, but it also presents environmental challenges. We're committed to working with industry, government, regulators and subject experts to respond to these challenges, address stakeholders concerns and work toward minimizing our environmental impact. I believe we can continue to develop this important resource in a way that meets society's expectations.

Is Petro-Canada considering scaling back its community partnership program or Olympic Games sponsorship?

Petro-Canada's success as an energy company depends on the support of people in many communities. We remain committed to all our partnerships, both at the local community grassroots level and the larger scale Olympic Games.

What is Petro-Canada's position on climate change actions and evolving regulations?

Climate change is one of the toughest environmental issues we face today and in the foreseeable future. It's a complex issue, which requires integrated solutions – solutions we want to be a part of. We're working to minimize our environmental footprint, including efforts to reduce greenhouse gases in Canada and abroad. We're working with our industry association and government officials to develop a climate change framework. And we're encouraging candid, two-way dialogue with our stakeholders.

What are the key factors to Petro-Canada's short- and long-term success?

First, the need for ***operational execution*** (safe and reliable operations) is as great as ever. This is how we will generate maximum cash flow in this environment. Second, we must use our ***financial strength*** prudently to manage our way through this economic downturn and come out well positioned on the other side. And finally, it's imperative to have ***quality growth projects*** for future development that will produce stable, long-term cash flows and help secure further opportunities. Plain and simple, Petro-Canada is strong on all three fronts.

We have a track record of solid operational reliability, businesses that generate robust cash flows, a strong financial position and a quality portfolio of assets. I am confident that Petro-Canada has the ***strength to deliver***.

Ron Brenneman
President and Chief Executive Officer

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), dated effective as of February 23, 2009, should be read in conjunction with the audited Consolidated Financial Statements and Notes for the year ended December 31, 2008, included within this 2008 annual report and the 2008 Annual Information Form (AIF). Financial data has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise specified. All dollar values are Canadian (Cdn) dollars, unless otherwise indicated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated. Graphs accompanying the text portray performance of the Company within its "value drivers," which are the key measures of performance in each segment of Petro-Canada's business. A glossary of financial terms, ratios and acronyms can be found on page 114 of this report.

BUSINESS ENVIRONMENT

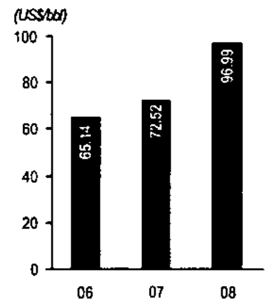
The major economic factors influencing Petro-Canada's upstream financial performance include crude oil and natural gas prices and foreign exchange, particularly the Cdn dollar/U.S. dollar rates (US). Crude oil and natural gas prices are affected by a number of factors, including the balance of supply and demand, weather and political events. Economic factors influencing Downstream financial performance include the level and volatility of crude oil prices, industry refining margins, levels of crude oil price differentials, demand for refined petroleum products, the degree of market competition and foreign exchange, particularly the Cdn dollar/U.S. dollar rates.

Business Environment in 2008

The year 2008 was one of the most volatile on record for oil markets. The first half of the year saw significant upward momentum in oil prices as weak supply growth fell short of robust demand growth in non-Organization of Economic Co-operation and Development (OECD) countries. Economic momentum slowed dramatically in the second half of the year as the global financial crisis intensified, depressing crude oil demand appreciably. By the end of 2008, demand was negative. The swings in oil prices through 2008 were also accompanied by record inflows, followed by record outflows, of investment dollars from commodity market funds. The price of North Sea Brent (Dated Brent) opened the year at just under $100 US/barrel (bbl), climbed to record highs of over $140 US/bbl in early July, and then fell steadily to under $45 US/bbl by early December. Despite the declines in the latter half of the year, the annual average price of Dated Brent was the highest ever at $96.99 US/bbl, approximately one-third above the 2007 average.

Average Crude Oil Prices Dated Brent at Sullom Voe

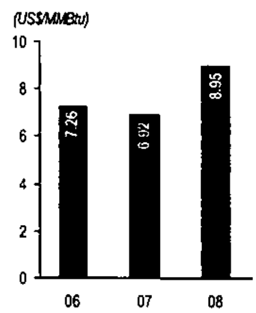
■ US$/bbl



In 2008, the international light/heavy crude (Dated Brent/Mexican Maya) price differential averaged $13.15 US/bbl, somewhat wider than the $12.67 US/bbl posted in 2007. Canadian light/heavy crude (Edmonton Light/Western Canada Select (WCS)) spreads narrowed in 2008 to $19.91 Cdn/bbl from $24.07 Cdn/bbl in 2007. Canadian heavy crudes continued to be sold at a greater discount to light crudes, compared with international heavy crudes. This is due to Canadian heavy crude oil production growing at a faster rate than North American investment to convert refineries to process heavy feedstock. The Canadian discount narrowed in 2008, however, as the supply of competing heavy oil imports from Mexico and Venezuela declined.

Average Natural Gas Prices Henry Hub

■ US$/MMBtu



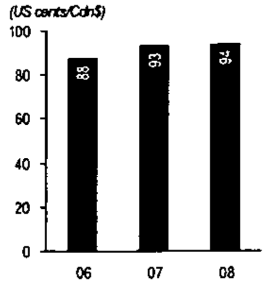
North American natural gas prices were very volatile in 2008. Natural gas prices at the Henry Hub ranged from over $13.50 US/million British thermal units (MMBtu) in July to under $6.50 US/MMBtu in November. Overall, Henry Hub prices averaged $8.95 US/MMBtu in 2008, about 30% higher than in 2007. The increase was due to higher crude oil prices, which raised the cost of distillate fuels that in turn competed with natural gas. In 2008, the Canadian natural gas price at the AECO-C hub rose 23%, somewhat less than U.S. prices, as the strength of the

Canadian dollar in the first half of the year offset some of the gains in natural gas prices.

The Canadian dollar was also extremely volatile in 2008, falling from parity with the U.S. dollar in the first half of the year to under 80 cents US by December. Overall, the Canadian dollar averaged 94 cents US in 2008, compared with 93 cents US in 2007. The strength of the Canadian currency in the first half of the year reduced some of the impact of stronger international prices on Canadian crude oil and natural gas prices. Similarly, the decline in the Canadian dollar in the second half of the year offset some of the impact from the declines in international crude oil and natural gas prices.

Average Canadian/U.S. Exchange Rate

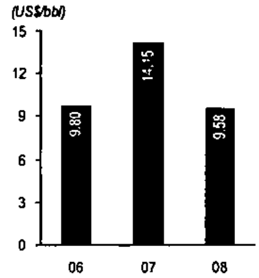
■ *US cents/Cdn$*



In the downstream sector, refined petroleum products sales in Canada increased by 0.5% in 2008, compared with a gain of 3.4% in 2007. Demand growth in 2008 was relatively stronger in Canada than in the U.S., but momentum slowed steadily through the year. The New York Harbor 3-2-1 crack spread, an indicator of overall refining margins, averaged $9.58 US/bbl in 2008, compared with $14.15 US/bbl in 2007. Declines in gasoline cracking margins more than offset gains in distillate cracking margins. With the exception of relatively brief hurricane-induced spikes in September, gasoline cracking margins were pressured downward by declining U.S. consumption. Distillate margins rose markedly, averaging over $19.61 US/bbl, as strong demand for diesel fuel from non-OECD countries and commodity producers led to sharply higher product exports from the U.S.

Average New York Harbor 3-2-1 Refinery Crack Spread

■ *US$/bbl*



Commodity Price Indicators and Exchange Rates

(averages for the years indicated)		2008	2007	2006
Crude oil price indicators *(per bbl)*				
Dated Brent at Sullom Voe	**US$**	**96.99**	72.52	65.14
West Texas Intermediate (WTI) at Cushing	**US$**	**99.65**	72.31	66.22
WTI/Dated Brent price differential	**US$**	**2.66**	(0.21)	1.08
Dated Brent/Mexican Maya price differential	**US$**	**13.15**	12.67	13.94
Edmonton Light	**Cdn$**	**102.83**	76.84	73.23
Edmonton Light/WCS (heavy) price differential	**Cdn$**	**19.91**	24.07	22.40
Natural gas price indicators				
Henry Hub *(per MMBtu)*	**US$**	**8.95**	6.92	7.26
AECO-C spot *(per thousand cubic feet – Mcf)*	**Cdn$**	**8.47**	6.89	7.28
Henry Hub/AECO basis differential *(per MMBtu)*	**US$**	**1.15**	0.80	1.09
New York Harbor 3-2-1 refinery crack spread *(per bbl)*[1]	**US$**	**9.58**	14.15	9.80
US$/Cdn$ exchange rate	**US$**	**0.94**	0.93	0.88

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, the 2007 and 2008 crack spread values are not directly comparable to 2006 values.

Competitive Conditions

It is increasingly challenging for the energy sector to find new sources of oil and natural gas. Petro-Canada is well positioned to successfully increase production of oil and natural gas and compete for new opportunities that could complement existing upstream resources. The Company has an estimated 14 billion barrels of oil equivalent (boe) of resources from which to develop new production, with approximately 68% of the resources located in Alberta's oil sands. With upstream business operations in Canada and internationally, the Company has the flexibility to pursue a wide range of opportunities. While the Company has significant operational scope, as measured by production levels, it remains a mid-sized global company. This means Petro-Canada has the operational capability and balance sheet strength to invest in large projects, but smaller investments can also have a meaningful impact on the Company's production levels and financial returns.

Petro-Canada is well positioned to compete in the petroleum product refining and marketing business in Canada. Petro-Canada has the second largest downstream business in Canada and is the "brand of choice." The Company conducts business in the downstream throughout Canada as an integrated business unit and participates in the refining, distribution and marketing of petroleum products. The Company also offers a wide range of ancillary non-petroleum goods and services, such as convenience retailing, automotive repair and car washes.

The Company's strong financial position, track record of successfully executing large capital projects and depth of management experience should enable it to continue to compete effectively in the current business environment.

Outlook for Business Environment in 2009

Prices for energy commodities are expected to remain volatile in 2009, reflecting the high degree of uncertainty associated with the global financial crisis and the unprecedented scale and scope of official stimulus measures being implemented around the world. On the demand side, the world economy has moved into recession in 2009 following one of the strongest and longest global expansions since the Second World War.

The global financial crisis has led to a marked increase in the cost and a large decrease in the availability of capital. The petroleum industry is highly capital intensive, requiring significant reinvestment rates in order to maintain output to offset natural reservoir declines. Reduced cash flows from lower commodity prices coupled with capital constraints will lead to lower supply growth over the coming years. Supply may also be influenced by the Organization of the Petroleum Exporting Countries (OPEC) production decisions.

More stringent environmental regulations are anticipated which, relative to the situation, will slow the growth rate of energy demand by directly or indirectly increasing the cost of consuming fossil fuels.

There are several downside risks for North American natural gas markets in 2009. Higher residential demand due to colder-than-normal temperatures this winter across most of North America has been offset by very weak industrial demand, the latter of which is expected to persist until the economy recovers. Slower economic growth in both Europe and Asia, where relatively higher natural gas prices attracted virtually all of the global liquefied natural gas (LNG) supply in 2008, could push some of these shipments back into the U.S. market in 2009. U.S. domestic natural gas supply rose strongly over the past year owing to innovative applications of horizontal drilling and fracturing technologies in non-conventional reservoirs (especially shale and tight-sands gas deposits). Although drilling activity declined sharply alongside the collapse in commodity prices and rising cost of capital, this is not expected to reverse the upward trend in domestic supplies until late 2009 at the earliest.

Barring refinery mishaps or accidents of nature, 2009 refining margins in the downstream are expected to be weaker than in 2008. North American refined petroleum products demand will likely remain well below aggregate refining capacity until the economy begins to recover.

Finally, the Canadian dollar is expected to remain loosely correlated with crude oil prices in 2009, providing some offset to fluctuations in international crude oil and natural gas prices.

Economic Sensitivities

The following table illustrates the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2008 net earnings had these changes occurred.

Sensitivities Affecting Net Earnings

Factor[1,2]		Change (+)		Annual Net Earnings Impact		Annual Net Earnings Impact
				(millions of Canadian dollars)		*($/share)*[3]
Upstream						
Price received for crude oil and natural gas liquids (NGL)[4]	$	1.00/bbl	$	54	$	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		(60)		(0.12)
Crude oil and NGL production *(barrels/day – b/d)*		1,000 b/d		15		0.03
Natural gas production *(million cubic feet/day – MMcf/d)*		10 MMcf/d		11		0.02
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		20		0.04
Seattle 3-2-1 crack spread	$	1.00 US/bbl		9		0.02
WTI/Dated Brent price differential	$	1.00 US/bbl		25		0.05
Dated Brent/Maya FOB price differential	$	1.00 US/bbl		5		0.01
WTI/synthetic price differential	$	1.00 US/bbl		14		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		(10)		(0.02)
Asphalt – % of Maya crude oil price		1%		2		–
Heavy fuel oil – % 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	$	31	$	0.06

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 at December 31, 2008.
4 This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent.
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. dollar-denominated debt. The impact refers to gains or losses on $2.9 billion US of the Company's U.S. dollar-denominated long-term debt and interest costs on U.S. dollar-denominated debt. Gains or losses on $1.1 billion US of the Company's U.S. dollar-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.

BUSINESS STRATEGY

Value Proposition and Strategy

The value proposition Petro-Canada offers to its investors can best be summarized as "Integrated Value from a Diversified Resource Base." The Company's business strategy continues to be:

- improving the profitability of the base business
  - meeting annual production guidance
  - selecting the right assets to develop and then driving for first quartile performance[1]
- taking a disciplined approach to profitable growth
  - leveraging existing assets
  - accessing new opportunities with a focus on long-life assets
  - building a balanced exploration program

The Company believes its structure and scope strategically position Petro-Canada to deliver long-term shareholder value. With a base in Canada, Petro-Canada is situated in a stable, resource-rich and demand-driven market. An ever-increasing international presence and integration across businesses provide the Company access to more value-adding growth opportunities and an ability to better manage risk through a diversified portfolio. As a mid-sized global company, even smaller sized investments can have a material impact. Through its major growth projects, Petro-Canada has visible and flexible growth over the next several years. The Company remains committed to developing energy resources responsibly and providing growth opportunities for employees.

Execution of the Strategy in 2008

Improving Base Business Profitability

For 2008, Petro-Canada focused on two areas to deliver improved base business profitability, delivering upstream production in line with updated annual guidance and continuing to improve safety and reliability performance. Safety, reliability and cost management are measures that are continuously tracked, reported and improved upon.

Through a focus on execution, the Company achieved upstream production at the high end of its guidance range of 400,000 to 420,000 barrels of oil equivalent/day (boe/d) in 2008. This strong production growth was largely due to strong reliability at most of the Company's major facilities.

Western Canada natural gas processing facilities operated at reliability rates of 99%. The two Downstream refineries and lubricants plant had a combined reliability index of 86. The lower Downstream reliability in 2008 was due to unplanned outages at the Edmonton refinery. The most significant improvements in 2008 were at the Terra Nova facility and the Oil Sands' MacKay River *in situ* operation, with reliabilities of 90% and 97%, respectively. The Company has a continued focus to improve facility reliability in 2009.

Corporate-wide, Petro-Canada views safety as an indicator of operational excellence. The Company has a Zero-Harm philosophy. This means the Company believes that work-related injuries and illnesses are foreseeable and preventable. The Company is committed to maintaining a first quartile safety record. In 2008, Petro-Canada achieved a Total Recordable Injury Frequency (TRIF) of 0.73, a 16% improvement over the previous year, and one of the best safety records in the sector.

Managing costs is another key to improving base business profitability. Petro-Canada has a disciplined approach to financial management with efforts constantly made across the Company to responsibly manage expenses and improve efficiencies. Petro-Canada entered 2009 with a strong liquidity position, providing the Company with flexibility to execute its capital program.

1 References to first quartile operations in this report do not refer to industry-wide benchmarks or externally known measures. The Company has a variety of internal metrics that define and track first quartile operational performance.

Maintaining Financial Discipline and Flexibility

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Fund Capital Expenditures with Cash Flow and Debt As Required	· fund $5.3 billion capital expenditure program through a combination of cash flow and access to capital markets, as needed · prioritize execution of projects · maintain investment grade credit ratings	· funded capital expenditure program of $6.4 billion from liquidity sources · exercised flexibility within major projects in response to business environment · maintained investment grade credit ratings of Baa2 from Moody's Investors Services (Moody's), BBB from Standard & Poor's (S&P) and A (low) from DBRS Limited (DBRS) · ended 2008 strong, with debt levels at 23.5% of total capital and a ratio of 0.7 times debt-to-cash flow from operating activities · maintained adequate liquidity, with a year-end cash balance of $1.4 billion and unutilized credit facility capacity of $4.7 billion	· fund $4.0 billion capital expenditure program from expected cash flow, cash on hand and accessing balance sheet strength, as needed · manage operating and capital costs within budgets · maintain investment-grade credit ratings
Fund Profitable Growth	· identify and invest in long-life assets	· made final investment decision (FID) on Syria Ebla gas project, signed Libya Exploration and Production Sharing Agreements (EPSAs), funded Edmonton refinery conversion project (RCP) and received approval for North Amethyst portion of White Rose Extensions · postponed making FID on Fort Hills Phase 1, MacKay River expansion (MRX) and Montreal coker	· invest in additional growth opportunities when there is a strong business case
Return Cash to Shareholders	· regularly review the dividend strategy to align with financial and growth objectives and shareholder expectations · buy back shares, when appropriate, with priority to first fund profitable growth	· increased quarterly dividend by 54% to $0.20/share · renewed normal course issuer bid (NCIB) program in June 2008, entitling the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions · purchased zero shares during 2008	· regularly review the dividend strategy to align with financial and growth objectives, and shareholder expectations · buy back shares when appropriate, with priority to first fund profitable growth

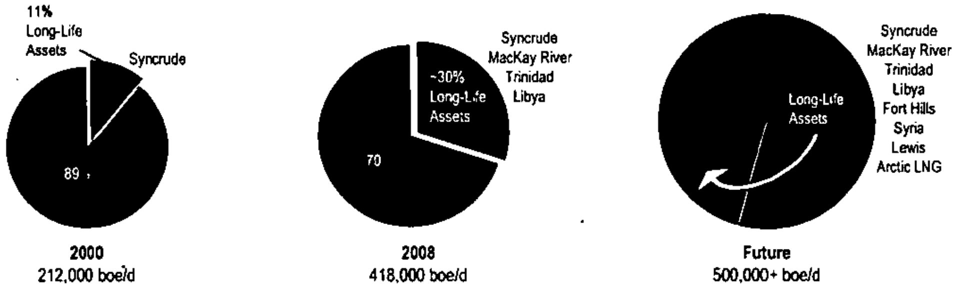
Long-Term Profitable Growth

Adding new material opportunities is fundamental to long-term growth. In 2008, one of Petro-Canada's priorities was to advance its seven major growth projects. Highlights included completing construction of the Edmonton RCP, signing six new Libya EPSAs and making a FID on the Syria Ebla gas development. In the East Coast business, project partners received regulatory approval for the North Amethyst development of the White Rose Extensions project to proceed. The Company also completed preliminary front-end engineering and design (FEED) work on the Fort Hills project, received regulatory approval for expansion of the MacKay River facility and progressed engineering on the Montreal coker project.

In pursuing these growth projects, Petro-Canada is seeking to increase the relative proportion of long-life resources in the portfolio as a means to deliver sustainable cash flow and earnings. With the exception of the White Rose Extensions, all of these major growth projects are considered long-life assets. In the upstream, Petro-Canada defines long-life assets as those projects that have more than 10 years of peak production and sustainable cash flow. In the Downstream, refineries and gasoline stations share the same long-life characteristics. These kinds of assets provide sustainable cash flow and make the Company less dependent on exploration success for growth. The Company also seeks to expand long-life assets from existing infrastructure.

Long-Life Production (%)

In 2008, about 30% of Petro-Canada's production came from assets considered long-life. Successful execution of the business strategy will mean a higher proportion of long-life resources in the future.



Along with long-life assets, the Company pursues profitable growth through a balanced exploration program. A balanced exploration program is one that provides a balanced risk/reward profile and that collectively adds to reserves over time. In 2008, Petro-Canada and its partners drilled 14 exploration wells.

Five of these wells were completed as discoveries and two were completed as successful appraisal wells. Drilling of an Alaskan well was suspended, and there is a plan for re-entry in 2009. Six wells were abandoned as dry holes or non-commercial discoveries and were written off. At year-end 2008, operations continued on one well.

This table represents exploration in International, East Coast Canada, Alaska and the Northwest Territories (NWT) but does not include Western Canada and U.S. Rockies.

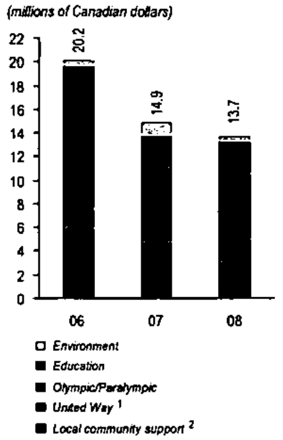
	2008 Results				2009 Outlook
(number of wells)	Discoveries – Oil	Discoveries – Natural Gas	Still being evaluated	Dry and abandoned	
North Sea	2	2	–	2	4
Syria	–	–	–	–	–
Libya	1	–	–	–	4
Trinidad and Tobago	–	4	–	2	–
Alaska	–	1	1	–	3
NWT	–	–	–	1	–
East Coast Canada	–	–	–	–	1
Total[1]	3	7	1	5	12

1 Two wells were carried over into 2008 from 2007.

Following our Principles for Responsible Investment and Operations

Cash and In-Kind Contributions of Nearly $14 Million in 2008
Years ended December 31 (unaudited)

(millions of Canadian dollars)



[1] Company contributions and campaign costs only (excludes employee donations).
[2] Cash contributions to communities from Petro-Canada's community partnerships program (including the Petro-Cares program), business units, plus in-kind donations.

Our principles guide our actions and track our performance in the areas of business conduct, community support, environment, working conditions and human rights.

Petro-Canada's Community Partnerships Program supports significant community initiatives relating to key business areas. Education and capacity building are themes that underpin all the Company's investments. The Company's community initiatives aim to create long-term programs with a measurable investment return for the Company and its partners.

There is a growing concern about the impact the energy sector has on the environment. The Company shares this concern and actively seeks to minimize the impact of Petro-Canada's operations on land, water and air. The Company's areas of focus are use of water, and management of greenhouse gas (GHG) emissions and air emissions.

Petro-Canada had approximately 6,100 employees and many contractors working on its behalf at year-end 2008. In 2008, Petro-Canada recruited more than 950 new employees. The Company is committed to providing them with a safe and rewarding place to work where they can learn and make a difference.

Following our Principles for Responsible Investment and Operations

PRIORITY	PRINCIPLES	2008 GOALS	2008 RESULTS	2009 GOALS
Business Conduct	· comply with applicable laws and regulations · apply our Code of Business Conduct wherever we operate · seek contractors, suppliers and agents whose practices are consistent with our principles	· update Code of Business Conduct and introduce interactive web-based training on the new Code of Business Conduct · continue to strengthen communication of Code of Business Conduct expectations with an increasing contractor workforce · improve new employee orientation process across the Company to emphasize Zero-Harm and Total Loss Management (TLM) culture and principles · implement online TLM training to strengthen employee understanding	· updated Code of Business Conduct · interactive web-based training completed by 4,419 employees and 408 contractors · delivered workshop-style anti-corruption training at nine Company locations, training both employees and contractors · implemented new employee orientation process, integrating TLM and Zero-Harm to reduce the risk of loss or injury · conducted online TLM training modules in four priority elements for 4,869 employees · developed online training to strengthen risk assessment capability	· update policy for the Prevention of Improper Payments · introduce interactive web-based training on the Policy for the Prevention of Improper Payments · review and update the Company's anti-trust and fair competition compliance program · integrate risk assessment methodology into all TLM processes, including the event management system

Following our Principles for Responsible Investment and Operations (continued)

PRIORITY	PRINCIPLES	2008 GOALS	2008 RESULTS	2009 GOALS
Community	• strive within our sphere of influence to ensure a fair share of benefits to stakeholders impacted by our activities • conduct meaningful and transparent consultation with all stakeholders • endeavour to integrate our activities with, and participate in, local communities as good corporate citizens	• improve the consistency and capability relative to engaging with stakeholders • solicit feedback from external stakeholders regarding the effectiveness of the Company's interactions • initiate and implement a social investment program that is integral to the Libya EPSAs • introduce a number of new key community partnerships in our education, environment and local community support areas • advance Olympic initiatives in anticipation of the 2010 Winter Olympics	• delivered training based on Stakeholder and Community Engagement principles to 134 stakeholder practitioners across all business units • integrated stakeholder issue management system into key projects and emergency response plans • solicited focused stakeholder feedback on specific projects • piloted a World Business Council for Sustainable Development (WBCSD) framework to guide investment proposals for Libya sustainable development program • extended long-term sponsorships, introduced new community partnerships and deepened existing partnerships • supported the Canadian Olympic and Paralympic teams in Beijing, and announced Petro-Canada Athlete Family Program for 2010 Games in Vancouver • launched Employee Olympic Centre website	• continue to broaden stakeholder engagement capability across operational roles and with contractors • update TLM standards and audit criteria to reflect stakeholder management framework expectations • integrate stakeholder engagement practices into North African development and exploration projects • work jointly with the Libya National Oil Corporation (NOC) on identifying projects for the Libya sustainable development program • enhance content of key community partnerships, identify synergies and increase stakeholder awareness of initiatives • launch 2010 Olympic glassware campaign to support Canadian athletes, and develop operations plan to "Fuel the Games" in Vancouver
Environment	• conduct our activities with sound environmental management and conservation practices • strive to minimize the environmental impact of our operations • work diligently to prevent any risk to community health and safety from our operations or our products • seek opportunities to transfer expertise in environmental protection to host communities	• integrate Water Principles into the environmental stewardship process • pilot carbon intensity performance measures • continue to review internal and external GHG mitigation opportunities • meet 2008 auditable emissions reporting requirements • commence development of second phase of environmental information management system for water and waste management • advance major water-related community partnership projects	• experienced 43 environmental regulatory exceedances, compared with 21 in 2007 • advanced water management plans through water risk assessments based on Water Principles • made limited progress on carbon performance measures • strengthened resources and capability in managing carbon mitigation opportunities • participated in Alberta carbon market • complied with Alberta regulations for verified emissions reporting • improved emission functionality of first phase of environmental information management system • created program content and materials for major water partnerships	• reinforce senior management focus on environmental regulatory exceedances in 2009 • develop and integrate relevant water measurement and reporting functionality into next phase of environmental information management system • pursue viable opportunities to purchase carbon credits • participate in WBCSD protocol development to better understand Petro-Canada's broader GHG emissions footprint • initiate work on development of ecosystem principles • build strength in water partnerships and promote publicly

Following our Principles for Responsible Investment and Operations (continued)

PRIORITY	PRINCIPLES	2008 GOALS	2008 RESULTS	2009 GOALS
Working Conditions and Human Rights	• provide a healthy, safe and secure work environment • honour internationally accepted labour standards prohibiting child labour, forced labour and discrimination in employment • respect freedom of association and expression in the workplace • not be complicit in human rights abuses • support and respect the protection of human rights within our sphere of influence	• establish enterprise-wide contractor engagement process for selection, performance monitoring and management • attract 925 new employees • develop capability in managing the social issues of a temporary foreign workforce • pilot a social risk assessment that will apply to new operations • enhance management, systems and work processes related to process safety • strengthen process for communicating and learning from internal high potential and serious events	• achieved TRIF of 0.73 in 2008, compared with 0.87 in 2007 • experienced a contractor work-related fatality at the Edmonton RCP in September 2008 • assessed current state, and best practices for contractor engagement and identified quick wins • attracted 951 new employees • assessed and developed mitigation plans for social risks related to bringing temporary foreign workers into Oil Sands project camps • developing standards, incorporating process safety criteria into TLM audits and capturing event data • established a formal process for reviewing internal and external events and ensuring that learnings reach the front line • conducted emergency response exercises in four out of five business groups	• develop enterprise-wide training for front-line supervisors to enhance their ability to execute work safely • develop processes, tools and expectations for stronger contractor engagement on safety • enhance emergency response advisor capability through increased training • upgrade emergency response command centre facility • implement new corporate standards for management of change and process safety competency • integrate use of social risk assessment process into project delivery model • review and strengthen Company's human rights management framework

Business Strategy Looking Forward

Key priorities for Petro-Canada in 2009 are striving to ensure that existing facilities run safely, reliably and efficiently through excellent execution and prudently managing the Company's financial strength. This same focus on execution and cost management will apply to the advancement of Petro-Canada's major projects over the next several years. Capital expenditures are expected to be $4.0 billion in 2009, down 38% from 2008, reflecting the Company's focus on the preservation of cash. In 2009, growth highlights are expected to include moving the Company's Board of Directors-approved projects (Libya EPSAs, which came on-stream in 2008, the North Amethyst portion of the White Rose Extensions project and the Syria Ebla gas development) ahead, as originally planned.

Major Approved Project	Target On-Stream Date
Libya EPSAs	2008
White Rose Extensions	2009
Syria Ebla Gas Development	2010

The three unsanctioned projects (Montreal coker, MRX and Fort Hills Phase 1) are on hold until the commodity and financial markets strengthen. The Company is reworking costs to improve project economics.

The Company also plans on drilling up to 12 exploration wells in the North Sea, Libya, East Coast Canada and the Alaska Foothills.

RISK MANAGEMENT

Risks Relating to Petro-Canada's Business

Petro-Canada's results are impacted by several risks and management's strategies for handling these risks. Management believes each major risk requires a unique response based on Petro-Canada's business strategy and financial tolerance. Some risks can be effectively managed through internal controls, business processes, insurance and hedging. Hedging is used in limited circumstances, mainly to mitigate Downstream risks associated with refinery feedstock costs. Petro-Canada's business risks include, but are not limited to, the following items. These risks could have a material adverse effect on the Company's business, financial conditions and results of operations.

A substantial or extended decline in crude oil or natural gas prices could have a material adverse effect on Petro-Canada.

The Company's financial condition depends substantially on the market prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have a material adverse effect on Petro-Canada's financial condition, as well as the value and amount of the Company's reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Petro-Canada's control. These factors include, but are not limited to, the actions of OPEC, world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Canadian natural gas prices are primarily affected by North American supply and demand, weather conditions, the level of industry inventories, political events, and, to a lesser extent, the price of alternate sources of energy.

Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production at some properties and unused long-term transportation commitments.

The margins realized for Petro-Canada'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 upon its ability to pass higher costs on to customers.

Petro-Canada's operations are subject to physical damage, business interruption and casualty losses.

Petro-Canada is subject to the operating risks associated with exploring for, and producing, oil and natural gas, as well as operating midstream and downstream facilities. These risks include blowouts, explosions, fires, gaseous leaks, equipment failures, migration of harmful substances, adverse weather conditions and oil spills. These risks could cause personal injury, could result in damage or destruction to oil and natural gas wells, formations, production facilities, other property and equipment, and the environment, and could interrupt operations. In addition, Petro-Canada's operations are subject to the risks related to transporting, processing and storing of oil, natural gas and other related products, drilling of oil and natural gas wells, and operating and developing oil and natural gas properties.

Factors that affect Petro-Canada's ability to execute projects could adversely affect business results.

Petro-Canada manages a variety of projects to support operations and future growth. Significant project cost overruns could make certain projects uneconomic. The Company's ability to execute projects depends upon numerous factors, which may include, but are not limited to, changes in project scope, labour availability and productivity, staff resourcing, availability and cost of material and services, design and/or construction errors, delays in regulatory approvals, the ability of partners to deliver on project commitments and access to capital funding. As a result, Petro-Canada may not be able to execute projects on time, on budget or at all.

Fluctuations in exchange rates create foreign currency exposure.

Due to the fact that energy commodity prices are primarily in U.S. dollars, Petro-Canada's revenue stream is affected by the Cdn/U.S. dollar exchange rate. The Company's net earnings are negatively affected by a strengthening Canadian dollar. Petro-Canada is also exposed to fluctuations in other foreign currencies, such as the euro and British pounds sterling.

Reduced liquidity in capital markets can limit the availability of capital and raise borrowing costs.

From time to time, Petro-Canada accesses the debt and/or equity markets to raise capital. The reasons may include, among other things, the need to raise financing for new operations, mergers, acquisitions and expansions. Reduced liquidity in the capital markets may restrict the Company's ability to raise the required financing and/or may significantly increase the associated cost of that capital. An inability to raise capital could jeopardize the ability of the Company to undertake a certain project and a higher cost of capital would reduce the profitability of that project.

A failure to acquire or find additional reserves would cause a decline in Petro-Canada's reserves and production levels.

The Company's future oil and natural gas reserves and production and, therefore, cash flows, are highly dependent upon success in exploiting Petro-Canada's current reserves and resources base and acquiring or discovering additional reserves and resources. Without reserves additions through exploration, acquisition or development activities, Petro-Canada's reserves and production will decline over time. Exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient to fund the Company's capital expenditures and external sources of capital become limited or unavailable, Petro-Canada's ability to make the necessary capital investments to maintain oil and natural gas reserves will be impaired. Costs to find and develop or acquire additional reserves also depend on success rates, which vary over time.

Petro-Canada's oil and natural gas reserves data and future net revenue estimates are subject to variability.

There are many uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond the Company's control. Estimates of economically recoverable oil and natural gas reserves are based upon a number of variables and assumptions. These include geoscientific interpretation, commodity prices, operating and capital costs and historical production from properties. These estimates have some degree of uncertainty and reserves classifications are best estimates. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributed to properties and classification of reserves based on recovery risk may vary substantially. Petro-Canada's actual production, revenues, taxes and development and operating expenditures related to reserves may vary materially from estimates.

Changes in governmental regulation affecting the oil and natural gas industry could have a material adverse impact on Petro-Canada.

The petroleum industry is subject to regulation and intervention by governments, including the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, regulation of the development and abandonment of fields (including restrictions on production) and, possibly, expropriation or cancellation of contract rights. As well, governments may regulate or intervene on prices, taxes, royalties and the exportation of oil and natural gas. Regulations may be changed in response to economic or political conditions. New regulations or changes to existing regulations that affect the oil and natural gas industry could reduce demand for natural gas or crude oil and increase Petro-Canada's costs.

Petro-Canada's foreign operations may expose the Company to risks, which could negatively affect results of operations.

The Company has operations in a number of countries with different political, economic and social systems. As a result, Petro-Canada's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over Petro-Canada's international operations. If a dispute arises in Petro-Canada's foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in the U.S. or Canada.

The Company has operations in Libya, which is a member of OPEC. Petro-Canada may operate in other OPEC-member countries in the future. Production in those countries may be constrained by OPEC quotas.

Petro-Canada's oil and natural gas production and refining operations impact communities and surrounding environments.

Those impacted by Petro-Canada's operations can become concerned over the use of resources, such as land and water, the perceived or real threat to human health, the potential impact on biodiversity, and/or possible societal changes to surrounding communities. The Company must secure and maintain formal regulatory approvals and licences in order to conduct operations. In addition, broader societal acceptance of Petro-Canada's activities is necessary for resource development. An inability for the Company to secure local community support, necessary regulatory approvals and licences, and broader societal acceptance can result in projects being delayed or stopped, resulting in higher project costs. Lack of local community and stakeholder support can lead to pressure to limit or shut down operations.

Petro-Canada is subject to environmental legislation in all jurisdictions where it operates. Changes in this legislation could negatively affect the Company's results of operations.

Petro-Canada is subject to environmental regulation under a variety of Canadian, U.S. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. This is collectively referred to below as environmental legislation.

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous and non-hazardous substances, including natural resources and waste, and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation requires that wells, facility sites and other properties associated with Petro-Canada's operations be operated, maintained, abandoned and reclaimed to the satisfaction of the applicable regulatory authorities. Certain types of operations, including exploration and development projects, and changes to certain existing projects, may require submitting and seeking the approval of environmental impact assessments (EIAs) or permit applications. Complying with environmental legislation can require significant expenditures, including costs for cleanup and damages due to contaminated properties. Failure to comply with environmental legislation may result in fines and penalties. Petro-Canada is also exposed to civil and criminal liability for environmental matters, including private parties commencing actions, new theories of liability and new heads of damages. Although it is not expected that the costs of complying with environmental legislation or dealing with environmental liabilities, as they are known today, will have a material adverse effect on Petro-Canada's financial condition or results of operations, no assurance can be made that the costs of complying with future environmental legislation will not have a material effect.

Petro-Canada operates in jurisdictions that have regulated or have proposed to regulate industrial GHG emissions. Jurisdictions that currently regulate GHG emissions include Alberta and the European Union. Jurisdictions that have proposed to regulate GHG emissions include the U.S., British Columbia (B.C.), Quebec, Ontario and Canada. Those jurisdictions that have announced the intent to regulate GHG emissions support cap-and-trade systems and, in some cases, have also proposed implementing complementary measures, including low carbon fuel standards. To date, these jurisdictions have started or have announced plans to start consultations on the design of their regulations, as well as explore opportunities to harmonize regulations across jurisdictions within North America. Petro-Canada participates in these consultations, either directly or through industry associations. In 2007, Petro-Canada established an internal senior management team to steward these activities and, in 2008, this organization was enhanced by creating the role of Director, Climate Change. While these jurisdictions have not published details on their proposed regulations or on their compliance mechanisms, many, most notably the U.S., have identified the importance of balancing the environment, economy and energy security when developing regulations. While it is premature to predict what impact these anticipated regulations may have on Petro-Canada and the broader oil and gas sector, Petro-Canada will likely face increased capital and operating costs in order to comply with these regulations, and these costs could be material. Petro-Canada is actively following policy development to ensure the Company is prepared to operate within a new framework.

Reduced asset reliability could adversely affect Petro-Canada's business.

Petro-Canada operates facilities in both the upstream and downstream sectors of the industry. A reduction in the reliability of these facilities as a result of, but not limited to, damage to equipment, plant or material, loss of production capability or operational integrity, or the extension of shutdown time could contribute to reduced profitability.

Counterparties exposure.

Petro-Canada is exposed to credit risk, and operational risk associated with counterparties' abilities to fulfil their obligations to the Company.

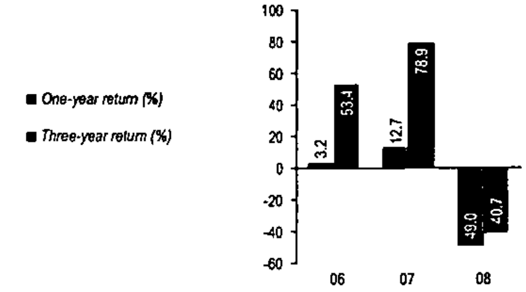
CONSOLIDATED FINANCIAL RESULTS

Analysis of Consolidated Earnings and Cash Flow

Consolidated Financial Results

On January 31, 2006, Petro-Canada closed the sale of the Company's producing assets in Syria. These assets and associated results are reported as discontinued operations and are excluded from continuing operations.

Shareholder Value



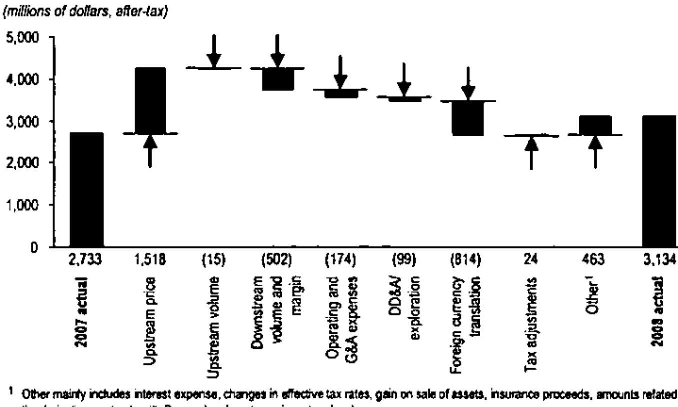
(millions of Canadian dollars, unless otherwise indicated)		2008	2007	2006
Net earnings		**$ 3,134**	**$ 2,733**	**$ 1,740**
Net earnings from discontinued operations		–	–	152
Net earnings from continuing operations		**$ 3,134**	**$ 2,733**	**$ 1,588**
Earnings per share from continuing operations *(dollars)*	– basic	**$ 6.47**	$ 5.59	$ 3.15
	– diluted	**6.43**	5.53	3.11
Earnings per share *(dollars)*	– basic	**$ 6.47**	$ 5.59	$ 3.45
	– diluted	**6.43**	5.53	3.41
Cash flow from continuing operating activities [1]		**6,522**	3,339	3,608
Debt		**4,749**	3,450	2,894
Cash and cash equivalents [2]		**1,445**	231	499
Average capital employed [2]		**$ 17,772**	$ 14,328	$ 12,868
Return on capital employed *(%)* [2]		**18.6**	19.8	14.3
Return on equity *(%)* [2]		**22.9**	24.5	17.5

1 Cash flow from continuing operating activities in 2007 was reduced by the payment of $1,145 million after-tax to settle the hedged portion of Buzzard production.
2 Includes discontinued operations.

2008 Compared with 2007

Net earnings increased 15% to $3,134 million in 2008, compared with $2,733 million in 2007. Higher realized crude oil prices, lower other expenses and lower tax adjustments contributed to the increase. These factors were partially offset by foreign currency translation losses, weaker Downstream refining margins, increased operating and general and administrative (G&A) expenses, higher exploration and depreciation, depletion and amortization (DD&A) expenses and lower upstream production.

2008 Versus 2007 Factor Analysis
Net Earnings from Continuing Operations
(millions of dollars, after-tax)



1 Other mainly includes interest expense, changes in effective tax rates, gain on sale of assets, insurance proceeds, amounts related to the derivative contracts with Buzzard and upstream inventory levels.

In 2008, net earnings included a number of items: a foreign currency translation loss on long-term debt of $606 million, a $255 million charge due to declining crude oil feedstock costs while using a "first-in, first-out" (FIFO) method for valuing inventories in the Downstream, charges due to the deferral of the Fort Hills FID of $156 million, a $215 million income tax recovery, a $126 million recovery related to the mark-to-market of stock-based compensation, a $52 million charge for asset impairment, $29 million in insurance proceeds, a $20 million insurance premium surcharge and a gain on sale of assets of $4 million.

In 2007, net earnings included a number of items: net losses on the derivative contracts associated with the hedged portion of Buzzard production of $331 million, a foreign currency translation gain on long-term debt of $208 million, a $191 million income tax recovery, a $97 million charge for asset impairment, a gain on sale of assets of $58 million, a $54 million charge related to the mark-to-market of stock-based compensation, $30 million in insurance proceeds and a $7 million insurance premium recovery.

Quarterly Information

Consolidated Quarterly Financial Results

(millions of Canadian dollars, unless otherwise indicated)	2008				2007			
	Quarter 1	**Quarter 2**	**Quarter 3**	**Quarter 4**	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Total revenue	**$ 6,586**	**$ 7,646**	**$ 8,286**	**$ 5,267**	$ 4,841	$ 5,478	$ 5,497	$ 5,434
Net earnings	**1,076**	**1,498**	**1,251**	**(691)**	590	845	776	522
Cash flow from (used in) operating activities [1]	**1,435**	**2,479**	**1,279**	**1,329**	1,166	1,435	1,340	(602)
Earnings per share *(dollars)*								
– basic	**$ 2.22**	**$ 3.10**	**$ 2.58**	**$ (1.43)**	$ 1.19	$ 1.71	$ 1.59	$ 1.08
– diluted	**$ 2.20**	**$ 3.07**	**$ 2.56**	**$ (1.43)**	$ 1.18	$ 1.70	$ 1.58	$ 1.07

1 Cash flow from (used in) continuing operating activities in the fourth quarter of 2007 was significantly reduced due to the payment of $1,145 million after-tax to settle the hedged portion of Buzzard production.

Revenue and net earnings variances from quarter to quarter resulted mainly from fluctuations in commodity prices and refinery cracking margins, the impact on production and processed volumes from maintenance and other shutdowns at major facilities, and the level of exploration drilling activity. For further analysis of quarterly results, refer to Petro-Canada's quarterly reports to shareholders available on the Company's website at www.petro-canada.ca.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

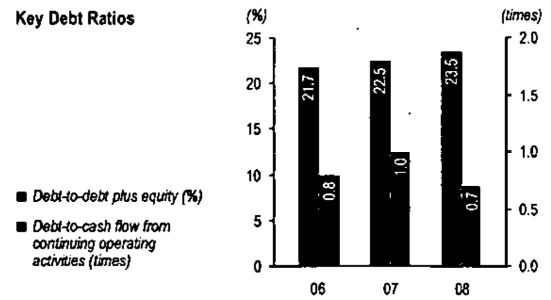
(millions of Canadian dollars)	2008	2007	2006
Cash flow from continuing operating activities	**$ 6,522**	**$ 3,339**	**$ 3,608**
Cash flow from discontinued operating activities	–	–	15
Net cash inflows (outflows) from:			
– investing activities	(5,384)	(3,647)	(2,738)
– financing activities	76	40	(1,175)
Increase (decrease) in cash and cash equivalents	$ 1,214	$ (268)	$ (290)
Cash and cash equivalents at end of year	**$ 1,445**	**$ 231**	**$ 499**
Cash and cash equivalents – discontinued operations	**$ –**	**$ –**	**$ –**

In 2008, cash flow from continuing operating activities was $6,522 million ($13.47/share), compared with $3,339 million ($6.83/share) in 2007. The increase in cash flow was primarily due to higher net earnings and a decrease in the operating working capital deficiency. In 2007, cash flow was significantly reduced due to the payment of $1,145 million after-tax to settle the hedged portion of Buzzard production.

Financial Ratios

	2008	2007	2006
Interest coverage from continuing operations *(times)*[1]			
Net earnings basis	21.5	26.0	19.2
EBITDAX basis[1]	31.3	39.2	27.0
Cash flow basis	33.7	27.2	27.1
Debt-to-cash flow from continuing operating activities *(times)*	0.7	1.0	0.8
Debt-to-debt plus equity *(%)*	23.5	22.5	21.7

1 Refer to the Glossary of Terms, Ratios and Acronyms on page 114 for methods of calculation.



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 continuing operating activities and debt-to-debt plus equity. Petro-Canada's debt-to-cash flow from continuing operating activities ratio, the key short-term measure, was 0.7 times at December 31, 2008, down from 1.0 times at year-end 2007. This was well within the Company's long-term range of no more than 2.0 times. Debt-to-debt plus equity, the long-term measure for capital structure, was 23.5% at year-end 2008, up from 22.5% at year-end 2007. This was below the long-term range of 25% to 35% for both years, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. In the future, from time to time, Petro-Canada may exceed long-term ranges for short periods of time, but always with the goal to return back to within the long-term ranges. Financial covenants associated with the Company's various debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The Company complied with all financial covenants as at December 31, 2008.

Operating Activities

Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, the operating working capital deficiency was $46 million at December 31, 2008, compared with an operating working capital deficiency of $565 million at December 31, 2007. The working capital deficiency was lower at December 31, 2008, primarily due to the increase in inventories from adoption of the FIFO method for valuing inventories, the increase to accounts receivable resulting from the effective unwinding of the accounts receivable securitization program and the decrease in accounts payable and accrued liabilities due to the recovery related to the mark-to-market valuation of stock-based compensation.

Investing Activities

Capital and Exploration Expenditures

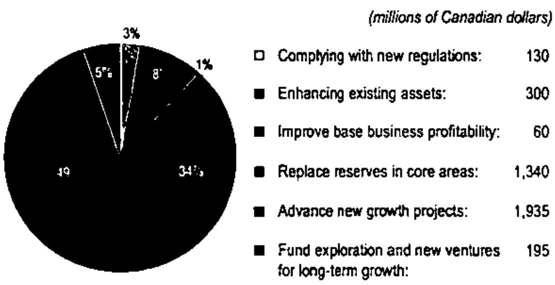
(millions of Canadian dollars)	2009 Outlook	2008	2007	2006
Upstream				
North American Natural Gas	$ 580	**$ 1,023**	$ 866	$ 788
Oil Sands	985	**1,063**	779	377
International & Offshore				
East Coast Canada	530	**276**	159	256
International [1]	1,270	**2,115**	762	760
	$ 3,365	**$ 4,477**	**$ 2,566**	**$ 2,181**
Downstream				
Refining and Supply	$ 460	**$ 1,651**	$ 1,214	$ 1,038
Sales and Marketing	70	**156**	155	142
Lubricants	30	**27**	27	49
	$ 560	**$ 1,834**	**$ 1,396**	**$ 1,229**
Shared Services	**$ 35**	**$ 33**	**$ 26**	**$ 24**
Total property, plant and equipment and exploration	**$ 3,960**	**$ 6,344**	**$ 3,988**	**$ 3,434**
Other assets	–	**29**	121	50
Total continuing operations	**$ 3,960**	**$ 6,373**	**$ 4,109**	**$ 3,484**
Discontinued operations	$ –	**$ –**	$ –	$ 1
Total	**$ 3,960**	**$ 6,373**	**$ 4,109**	**$ 3,485**

1 International excludes capital expenditures related to the Syrian producing assets, which were sold in 2006 and are reflected as discontinued operations.

Capital and exploration expenditures were $6,373 million in 2008, up 55% compared with $4,109 million in 2007, mainly reflecting higher investment in Libya, the Oil Sands and the Edmonton RCP.

In 2009, spending on new growth projects is expected to decrease substantially. Approximately half of planned capital expenditures support delivering profitable new growth and funding exploration and new ventures. This is down by more than $2 billion, compared with the same categories in 2008. The remaining half of 2009 planned capital expenditures is directed toward replacing reserves in core areas, enhancing existing assets, improving base business profitability and complying with new regulations.

2009 Capital Program from Continuing Operations



Financing Activities and Dividends

Sources of Capital Employed

(millions of Canadian dollars)	2008	2007	2006
Short-term notes payable	$ -	$ 109	$ –
Long-term debt, including current portion	4,749	3,341	2,894
Shareholders' equity	15,475	11,870	10,441
Total	**$ 20,224**	$ 15,320	$ 13,335

Total debt increased to $4,749 million at December 31, 2008, compared with $3,450 million at the previous year end. The increase in debt occurred due to a debt issuance in the second quarter of 2008, as well as the impact of a weakening Canadian dollar.

2008 Financing Activities

During 2008, Petro-Canada increased its syndicated committed credit facilities from $2,200 million to $3,570 million. At December 31, 2008, the Company's syndicated bilateral demand credit facilities totalled $777 million. A total of $348 million of the Company's credit facilities was used for letters of credit and overdraft coverage. Subsequent to December 31, 2008, the Company's liquidity was increased by $244 million through the addition of a bilateral committed credit facility. The syndicated facilities, which are in place until 2013, may also be used to provide liquidity support to a commercial paper program. The Company had no commercial paper outstanding at December 31, 2008 and does not plan to issue commercial paper in the near term.

In 2008, the Company issued $600 million US of 10-year notes, bearing interest at the rate of 6.05% per year, and $900 million US of 30-year notes, bearing interest at the rate of 6.80% per year, 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 March 31, 2008.

During 2008, the Company's $480 million accounts receivable securitization program was effectively unwound because it was no longer a cost-effective means of borrowing. The program remains outstanding as a liquidity source until June 24, 2009.

As at December 31, 2008, the credit ratings of the Company's unsecured long-term debt securities were Baa2 with a stable outlook by Moody's, BBB with a stable outlook by S&P and A (low) with a Negative Trend by DBRS. Petro-Canada's short-term debt securities are rated R-1 (low) with a Negative Trend by DBRS. A Positive or Negative Trend is not an indication that a rating change is imminent. Rather, a Positive or Negative Trend represents an indication that there is a greater likelihood that the rating could change in the future than would be the case if a Stable Trend was assigned to the security. A credit rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

The Company's financial capacity and flexibility remain strong despite the recent turmoil in the financial markets. This is due to the Company's continuing ability to generate cash flow, having access to existing cash balances and significant credit facility capacity, and requiring no near-term refinancing. For 2009, the Company expects to cover its capital program with cash flow, cash and, if necessary, from available credit facilities. The Company will monitor energy and financial markets through the year and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures accordingly.

Returning Cash to Shareholders

Petro-Canada'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.

Petro-Canada 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/share, commencing with the dividend payable on October 1, 2008. Total dividends paid in 2008 were $320 million ($0.66/share), compared with $255 million ($0.52/share) in 2007.

Petro-Canada's current NCIB program entitles the Company to repurchase up to 5% of its outstanding common shares from June 22, 2008 to June 21, 2009, subject to certain conditions. Throughout the year 2008, the Company did not repurchase any of its shares, compared with 16 million in 2007. Future share repurchases will depend on excess cash available after consideration of the Company's priority uses of cash.

	Shares Repurchased		Average Price ($/share)		Total Cost	
Period	**2008**	2007	**2008**	2007	**2008**	2007
Full year	-	15,998,000	**$** -	$ 52.42	**$** -	$ 839 million

Off Balance Sheet

The Company has certain retail licensee and wholesale marketing agreements that would constitute variable interest entities as described in Note 29 to the Consolidated Financial Statements. These entities are not consolidated because Petro-Canada is not the primary beneficiary and, therefore, consolidation is not required. The Company's maximum exposure to losses from these arrangements would not be material. Other off balance sheet activities are limited to the accounts receivable securitization program, which does not meet the criteria for consolidation and pursuant to which there are no amounts currently outstanding.

Pension Plans

At year-end 2008, Petro-Canada's defined benefit pension plans were under funded by $407 million, compared with an under funded position of $282 million at year-end 2007. For both the defined benefit and defined contribution pension plans, the Company made cash contributions of $67 million and recorded a pension expense of $93 million before-tax in 2008. This compares with $121 million of cash contributions and $81 million before-tax of pension expense in 2007. The Company expects to make pension contributions of approximately $62 million in 2009.

Contractual Obligations – Summary

	Payments due by period				
(millions of Canadian dollars)	**Total**	2009	2010-2011	2012-2013	2014 and thereafter
Unsecured debentures and senior notes [1]	**$ 10,729**	$ 305	$ 610	$ 975	$ 8,839
Capital lease obligations [1]	**119**	11	22	24	62
Operating leases	**2,082**	484	516	213	869
Transportation agreements	**1,436**	197	332	230	677
Product purchase/delivery obligations	**12,733**	3,361	3,242	1,918	4,212
Exploration work commitments [2]	**769**	381	291	85	12
Asset retirement obligations	**5,389**	54	106	119	5,110
Other long-term obligations [3, 4]	**3,786**	661	1,600	473	1,052
Total contractual obligations	**$ 37,043**	$ 5,454	$ 6,719	$ 4,037	$ 20,833

1 Obligations include related interest.

2 Excludes other amounts related to the Company's expected future capital spending. Capital spending plans are reviewed and revised annually to reflect Petro-Canada's strategy, operating performance and economic conditions. For further information regarding future capital spending plans, refer to the business segment and investing activities discussions in the 2008 MD&A.

3 Includes processing agreement with Suncor Energy Inc., Libya EPSA signature bonus, Fort Hills purchase obligation, pension funding obligations for the periods prior to the Company's next required pension plan valuation and other obligations. Pension obligations beyond the next required pension valuation date were excluded due to the uncertainty as to the amount or timing of these obligations.

4 Petro-Canada is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company. The table excludes amounts for these contingencies due to the uncertainty as to the amount or timing of any settlements.

During 2008, Petro-Canada's total contractual obligations increased by $5.3 billion, mainly due to an additional $1.5 billion US of unsecured senior notes issued in May, losses on the translation of foreign currency denominated unsecured debentures and senior notes and increased estimates for asset retirement obligations. This was partially offset by decreased product purchase obligations.

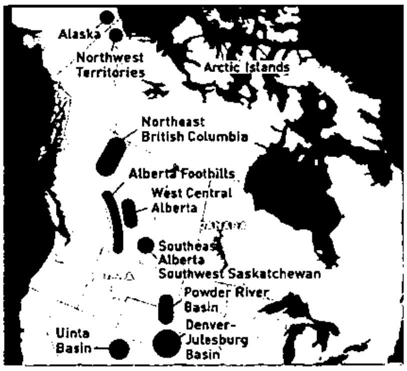
UPSTREAM

Petro-Canada's upstream operations consisted of three business units in 2008: North American Natural Gas, with production in Western Canada and the U.S. Rockies; Oil Sands with operations in northeast Alberta; and International & Offshore. International & Offshore has two segments: East Coast Canada, with three major developments offshore Newfoundland and Labrador; and International, where the Company is active in two core areas: North Sea and Other International (Libya, Syria and Trinidad and Tobago). The diverse asset base provides a balanced portfolio and a platform for long-term growth.

North American Natural Gas

Business Summary and Strategy

North American Natural Gas explores for and produces natural gas, crude oil and NGL in Western Canada and the U.S. Rockies. This business also markets natural gas in North America and has established resources in Alaska, the NWT and Arctic Islands.



The North American Natural Gas strategy is to be a significant market participant by accessing new and diverse natural gas supply sources in North America. Key features of the strategy include:

- optimizing core properties in Western Canada and in the U.S. Rockies
- targeting 50% to 60% reserves replacement
- increasing focus on unconventional exploration in Western Canada and the U.S. Rockies
- building the northern resource base for long-term growth

North American Natural Gas Financial Results

(millions of Canadian dollars)	**2008**	2007	2006
Net earnings	**$ 344**	**$ 191**	**$ 405**
Cash flow from continuing operating activities	**$ 1,055**	$ 725	$ 651
Expenditures on property, plant and equipment and exploration[1]	**$ 1,023**	$ 866	$ 788
Total assets	**$ 4,605**	$ 4,119	$ 4,151

1 In 2008, Petro-Canada made a small acquisition of oil production and exploration land located in the Denver-Julesburg Basin.

2008 Compared with 2007

North American Natural Gas contributed $344 million of net earnings, up significantly from $191 million in 2007. Strong natural gas prices, higher U.S. Rockies production and lower exploration expenses were partially offset by lower Western Canada production, increased operating costs and increased DD&A expenses.

Net earnings in 2008 included a loss on sale of assets of $91 million, a charge of $28 million for a discontinued pilot project in northern B.C. and a charge of $24 million related to accumulated project development costs for the proposed LNG re-gasification facility at Gros-Cacouna, Quebec, which has been postponed due to global LNG business conditions. Net earnings in 2007 included a $97 million charge related to the impairment of coal bed methane (CBM) assets in the U.S. Rockies, a $41 million gain on sale of assets and an $8 million income tax recovery.

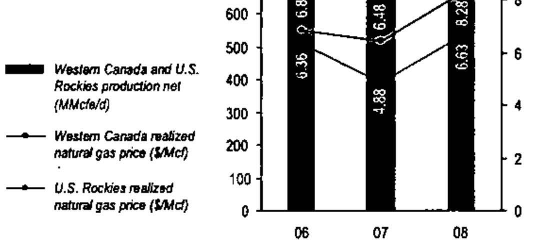
North American Natural Gas production was strong in 2008 due to increased production in the U.S. Rockies and strong performance in Western Canada, which significantly offset natural declines. Oil and natural gas production averaged 665 million cubic feet of gas equivalent/day (MMcfe/d) in 2008, compared with 674 MMcfe/d in 2007, as natural declines in Western Canada were partially offset by U.S. Rockies production growth. Natural gas commodity prices remained strong over the course of 2008. The North American realized natural gas price averaged $8.05/Mcf in 2008, up 28% from $6.30/Mcf in 2007.

2008 Operating Review and Strategic Initiatives

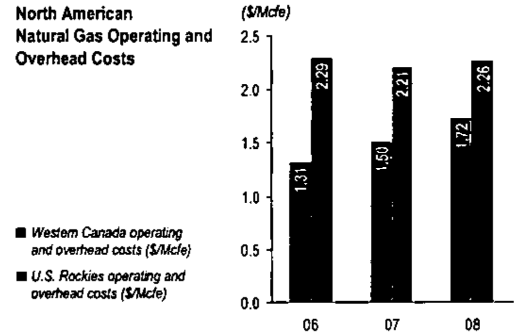
The North American Natural Gas business is selectively investing to optimize the existing core assets in Western Canada and the U.S. Rockies, focusing exploration in these basins and building the northern resource base for the longer term.

2008 Operating Review

North American Natural Gas Production and Realized Natural Gas Price



North American Natural Gas Operating and Overhead Costs



	2008	2007	2006
Production net *(MMcfe/d)*			
Western Canada	**562**	590	646
U.S. Rockies	**103**	84	55
Total North American Natural Gas production net	**665**	674	701
Western Canada realized natural gas price *($/Mcf)*	**$ 8.28**	$ 6.48	$ 6.88
U.S. Rockies realized natural gas price *($/Mcf)*	**$ 6.63**	$ 4.88	$ 6.36
Western Canada operating and overhead costs *($/thousand cubic feet of gas equivalent – $/Mcfe)*	**$ 1.72**	$ 1.50	$ 1.31
U.S. Rockies operating and overhead costs *($/Mcfe)*	**$ 2.26**	$ 2.21	$ 2.29

Western Canada

Western Canada production averaged 562 MMcfe/d in 2008, down 5% from 590 MMcfe/d in 2007. Exploration and development drilling activity in Western Canada resulted in 292 successful wells (gross), for an overall success rate of 97% in 2008. Western Canada realized natural gas price was $8.28/Mcf in 2008, compared with $6.48/Mcf in 2007. Western Canada operating and overhead costs were $1.72/Mcfe in 2008, up from $1.50/Mcfe in the previous year. The operating and overhead cost increase in Western Canada reflected industry-wide cost pressures for materials, fuel and labour, combined with lower production.

U.S. Rockies

U.S. Rockies production averaged 103 MMcfe/d in 2008, up 23% from 84 MMcfe/d in 2007. The increase reflected the ramp up of production from CBM fields in the Powder River Basin and increased drilling activity in the Denver-Julesburg Basin. Exploration and development drilling activity in the U.S. Rockies during 2008 resulted in 287 gross wells, up from 150 wells in 2007. U.S. Rockies realized natural gas price was $6.63/Mcf in 2008, up 36% from $4.88/Mcf in 2007. U.S. Rockies operating and overhead costs were $2.26/Mcfe in 2008, up from $2.21/Mcfe in 2007 due to industry-wide cost pressures for materials, fuel and labour.

2008 Strategic Initiatives

In Western Canada, the Company continued its planned shallow tight gas drilling program in the Medicine Hat, Alberta area, drilling 271 wells in 2008. The business expects to drill another 280 wells in 2009. In the other core areas of B.C. and Alberta, the Company continued to optimize existing fields, with the drilling of more than 30 exploration and development wells in 2008. As part of the Company's ongoing optimization of its portfolio of assets, Petro-Canada completed the sale of its Minehead assets in Western Canada, resulting in 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.

During 2008, the Company and its joint venture partners advanced its exploration activities in Alaska with a two-well program. The Kwijika well drilled in the NWT was dry and abandoned.

The Company sees long-term potential for the development of Arctic Island natural resources discovered in the 1970s and 1980s. The two largest assets Petro-Canada holds in the region are the Drake and Hecla fields on Melville Island. In 2008, a small team advanced a feasibility study to the point where uncertainty regarding regulatory approval timing was identified as a significant issue. The Company will continue to work with governments and stakeholders to streamline this process but, in the meantime, the Company has slowed down Arctic Island efforts.

Capital expenditures in 2008 totalled $1,023 million, with $451 million for exploration and development of natural gas in Western Canada, $498 million for U.S. Rockies exploration and development, and $74 million for other natural gas opportunities in North America.

Outlook

Production expectations in 2009

- production is expected to average about 570 MMcfe/d net of natural gas, crude oil and NGL

Action plans in 2009

- drill approximately 304 gross wells in Western Canada and approximately 241 gross wells in the U.S. Rockies
- three-well program planned for the Alaska Foothills

Capital spending plans in 2009[1]

- capital program of approximately $580 million is planned for North American Natural Gas
  - approximately $320 million for replacing reserves and maintenance in Western Canada and U.S. Rockies
  - approximately $180 million for growth opportunities in the U.S. Rockies
  - approximately $40 million directed to exploration and developing long-term supply opportunities in the Far North
  - approximately $40 million to enhance existing assets, comply with regulations and improve base business profitability

1 Petro-Canada will monitor energy and financial markets through 2009 and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures, as necessary.

Link to Petro-Canada's Corporate and Strategic Priorities

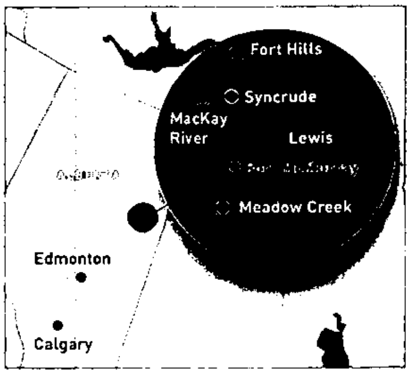
The North American Natural Gas business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2008 and goals for 2009.

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	· continue to selectively optimize Western Canada core assets · continue U.S. Rockies CBM and tight natural gas development · target 50% to 60% reserves replacement from these core assets · focus exploration activity in Western Canada, with increasing emphasis on the U.S. · advance exploration prospects in the NWT and Alaska · initiate an Arctic LNG feasibility study	· implemented drilling and optimization initiatives, resulting in lower decline rates · drilled 287 gross wells in the U.S. Rockies · continued to increase exploration focus in the U.S. Rockies and B.C. shale gas · participated in three wells in Alaska and NWT, resulting in one gas discovery, one dry and abandoned and one suspended as planned · progressed Arctic LNG feasibility study, encountering uncertainty with regard to regulatory approval timing	· continue to optimize Western Canada and U.S. core assets · target 50% to 60% reserves replacement from core assets · focus exploration activity in Western Canada and U.S. Rockies with an emphasis on unconventional exploration · advance exploration prospects in Alaska
Driving for First Quartile Operation of Our Assets	· continue to focus on safety and reliability performance · continue to leverage costs through strategic alliances and preferred suppliers	· maintained reliability of 99% at Western Canada natural gas processing facilities · delivered value to the organization through preferred supplier relationships, while continuing to ensure competitive supply costs through selective bidding	· continue to focus on safety and reliability performance · continue to leverage costs through strategic alliances and preferred suppliers · renegotiate contracts to reflect economic environment
Continuing to Work at Being a Responsible Company	· continue to focus on TRIF and maintain low regulatory exceedances · conduct internal stakeholder engagement training for project managers and other key business roles · strengthen approach to investigating and learning from events	· TRIF decreased to 1.31, compared with 1.54 in 2007 · experienced eight environmental regulatory exceedances in 2008, compared with three in 2007 · conducted training for stakeholder practitioners, project managers and key contractors · set up a formal process to identify and communicate key learnings from significant events	· pursue initiatives aimed at developing front-line supervisory capability in safety management · develop a water management plan for operations in areas of water scarcity and develop measures related to usage and capacity of the source · continually improve community emergency response programs

Oil Sands

Business Summary and Strategy

Petro-Canada estimates that it has 1.2[1] billion bbls of total Oil Sands proved plus probable reserves and 9.5[2] billion bbls of total Oil Sands Contingent and Prospective Resources. The Company's major Oil Sands interests include a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River *in situ* bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 60% ownership in and operatorship of the proposed Fort Hills oil sands mining project, and extensive oil sands acreage considered prospective for *in situ* development of bitumen resources.



● Directly operated
● Non-operated

The Oil Sands strategy for profitable growth includes:

- integrated development of resources to maximize leverage of infrastructure and to promote long-term stability of financial returns
- being positioned to capture the value opportunities inherent in long-life projects
- applying a phased and disciplined approach to development of capital-intensive projects to allow rigorous cost management and to create opportunities to benefit from evolving technology

The Company has chosen to participate in the full oil sands value chain due to its resource potential and strong position with bitumen upgrading capacity. Petro-Canada has processing capacity through Syncrude and Suncor Energy Inc. In 2008, the Company converted the conventional crude oil train at its Edmonton refinery to refine oil sands-based feedstock from northern Alberta. This conversion, along with the existing synthetic crude supply, resulted in the refinery being able to run on an exclusive diet of oil sands-based feedstock. This connection between resource and upgrading capacity should provide more economic certainty in a business where volatile light/heavy differentials affect bitumen pricing.

Oil Sands Financial Results

(millions of Canadian dollars)	**2008**	2007	2006
Net earnings	**$ 334**	**$ 316**	**$ 245**
Cash flow from continuing operating activities	**$ 622**	$ 512	$ 499
Expenditures on property, plant and equipment and exploration	**$ 1,063**	$ 779	$ 377
Total assets	**$ 4,566**	$ 3,659	$ 2,885

2008 Compared with 2007

Oil Sands contributed a record $334 million of net earnings, up 6% from $316 million in 2007. Higher realized prices at Syncrude and MacKay River, in addition to stronger MacKay River production were partially offset by lower Syncrude production and increased operating costs at both Syncrude and MacKay River.

Net earnings in 2008 included charges due to the deferral of the Fort Hills FID of $156 million. Net earnings in 2007 included a $62 million income tax recovery.

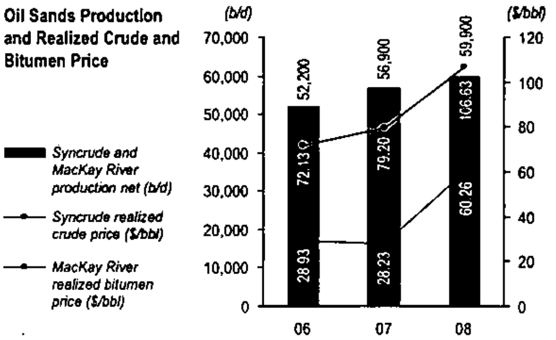
1 These reserves numbers represent the sum of oil sands mining and oil and gas activities, including probable reserves, and are presented before royalties. Reporting reserves in this manner does not conform to SEC standards and is for general supplemental information only.

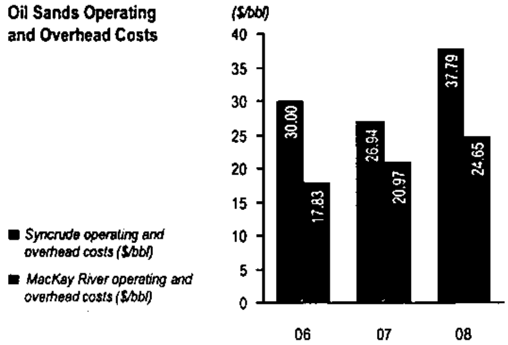
2 25% of total Oil Sands resources are risked Prospective Resources and 75% are Contingent Resources. See "Legal Notice – Petro-Canada disclosure of reserves" for additional risks to develop resources.

Strong production and reliability at MacKay River were highlights of 2008 performance. Syncrude realized price for synthetic crude oil averaged $106.63/bbl in 2008, up from $79.20/bbl in 2007. MacKay River realized price for bitumen averaged $60.26/bbl in 2008, compared with $28.23/bbl in 2007. Oil Sands production averaged 59,900 b/d net in 2008, compared with 56,900 b/d net in 2007.

2008 Operating Review and Strategic Initiatives

2008 Operating Review





	2008	2007	2006
Production net *(b/d)*			
Syncrude	**34,700**	36,600	31,000
MacKay River	**25,200**	20,300	21,200
Total Oil Sands production net	**59,900**	56,900	52,200
Syncrude realized crude price *($/bbl)*	**$ 106.63**	$ 79.20	$ 72.13
MacKay River realized bitumen price *($/bbl)*	**$ 60.26**	$ 28.23	$ 28.93
Syncrude operating and overhead costs *($/bbl)*	**$ 37.79**	$ 26.94	$ 30.00
MacKay River operating and overhead costs *($/bbl)*	**$ 24.65**	$ 20.97	$ 17.83

Syncrude's production averaged 289,000 b/d gross (34,700 b/d net) in 2008, compared with 305,000 b/d gross (36,600 b/d net) in 2007. Syncrude production was negatively impacted by turnarounds at Cokers 8-1 and 8-2 in 2008. Higher unit operating costs were mainly due to lower production, higher costs associated with moving additional overburden to increase exposed minable ore inventory, higher maintenance costs and higher natural gas costs. The total royalty paid in 2008 equated to a rate of 14% of gross revenues. In the fourth quarter, Petro-Canada and its partners in Syncrude concluded negotiations with the Government of Alberta regarding the province's desire for Syncrude to move to the New Alberta Royalty Framework recommendations in advance of the expiry of its existing royalty agreement in 2015.

MacKay River's average production increased to 25,200 b/d in 2008, up 24% compared with 20,300 b/d in 2007. Higher production reflected increased reliability and capacity at MacKay River. MacKay River reliability averaged 97% in 2008, up from 87% in 2007, when operational upsets occurred. Unit operating and overhead costs increased by 18% in 2008, averaging $24.65/bbl, compared with $20.97/bbl in 2007. Higher unit operating costs were due to higher maintenance and repair costs, a major turnaround and higher natural gas costs, partially offset by increased production for the year.

2008 Strategic Initiatives

In the first quarter of 2008, Petro-Canada received regulatory approval for the proposed MacKay River 40,000 b/d *in situ* expansion project. The MRX project is on hold until commodity prices and financial markets strengthen. Petro-Canada is pursuing cost-saving opportunities, including using international engineering, procurement and construction (EPC) contractors on a lump-sum basis.

In June 2007, Petro-Canada and its Fort Hills partners completed and announced the design basis and initiated the detailed FEED for Fort Hills Phase 1, which consists of the proposed Fort Hills mine and upgrader. At the completion of the FEED phase in September 2008, the estimated costs to complete the project increased by approximately 50%. The FID on the mining portion of the project is being deferred until the extension of the Fort Hills mine leases is resolved, costs can be reduced and commodity prices and financial markets strengthen. In 2008, the Fort Hills upgrader portion of the project was put on hold, and a decision on whether to proceed with the upgrader will be made at a later date. Bitumen production from the first phase of the mine is expected to be about 160,000 b/d gross (96,000 b/d net).

The Fort Hills Energy Limited Partnership has entered into an agreement, subject to the FID, with Enbridge Pipelines (Athabasca) Inc. to develop pipeline and terminalling facilities to meet the requirements of the Fort Hills mine Phase 1 and subsequent phases of the project.

The partners selected Sturgeon County, 40 kilometres northeast of Edmonton, as the location for the proposed upgrading facility to process bitumen from the Fort Hills mine. The upgrader will use delayed coking technology to convert Fort Hills' bitumen into light synthetic crude oil. Late in 2006, Petro-Canada filed the regulatory application for the Fort Hills upgrader. Conditional Energy Resources Conservation Board (ERCB) regulatory approval was received in January 2009. While the upgrader investment decision is being delayed, FEED is being fully completed and some long-lead equipment already ordered will be received and securely stored. The upgrader will remain in a holding status that permits re-engagement.

In two of the Oil Sands leases granted to the Fort Hills Energy Corporation by the Alberta government, there are several conditions, including a production milestone requiring that a mine be completed and producing 100,000 b/d gross (60,000 b/d net) of bitumen by mid-2011. Discussions are in progress with the Government of Alberta to amend the two Oil Sands leases. In the event that an amendment is not achieved and that the Fort Hills Partnership is unable to meet the existing conditions associated with the two leases, the Alberta government may impose a performance deposit or cancel the two leases if the performance deposit is not provided within the applicable time period.

Oil Sands capital expenditures of $1,063 million in 2008 included $751 million for the Fort Hills project, $41 million for the MRX, $168 million for MacKay River, $90 million at the Syncrude operations and $13 million for other Oil Sands projects.

Outlook

Production expectations in 2009

- Petro-Canada's share of Syncrude production is expected to average 38,000 b/d net
- MacKay River bitumen production is expected to average 27,000 b/d net, which includes two major 10- to 15-day planned maintenance turnarounds

Growth plans

- work to improve reliability at Syncrude and MacKay River
- progress SAGD technology through research and development

Capital spending plans in 2009[1]

- capital program of approximately $985 million is planned for Oil Sands
  - approximately $745 million for new growth opportunities, the majority of which is to advance the Fort Hills project (forecast to be $348 million) and for facilities, drilling and infrastructure for the MRX project (forecast to be $325 million)
  - approximately $210 million to enhance existing operations, comply with regulations and improve the base business profitability at Syncrude and MacKay River
  - approximately $30 million to replace reserves through ongoing pad development at MacKay River

1 Petro-Canada will monitor energy and financial markets through 2009 and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures, as necessary.

Oil Sands production is expected to increase to 65,000 b/d net in 2009, compared with actual production of 59,900 b/d net in 2008. Higher expected production in 2009 is due to higher volumes anticipated at both Syncrude and MacKay River. The total Syncrude royalty payable in 2009 is expected to be approximately 12% of gross bitumen revenue, depending on crude prices. The total MacKay River royalty payable in 2009 is expected to be approximately 2% of gross bitumen revenue, depending on crude prices.

With the completion of the Fort Hills Phase 1 and MRX projects, Petro-Canada's production from Oil Sands is expected to grow to more than 200,000 b/d net. Beyond that, the Company has the potential to grow the Oil Sands business to approximately 300,000 b/d net. Petro-Canada is focused on capturing the opportunities in its Oil Sands strategy, including taking advantage of a low-cost environment, while addressing the challenges of environmental and stakeholder issues. As an experienced and responsible operator, Petro-Canada is well positioned to meet these challenges.

Link to Petro-Canada's Corporate and Strategic Priorities

The Oil Sands business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2008 and goals for 2009.

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	• complete Fort Hills FEED and make FID in the third quarter of 2008 • order long-lead items for Fort Hills project • continue to ramp up Syncrude Stage III expansion • receive regulatory decision on MRX project • continue to advance MRX project in preparation for the FID in the first quarter of 2009 • receive regulatory decision on the Fort Hills upgrader	• completed Fort Hills Phase 1 FEED • deferred making the FID for Fort Hills mine due to more than a 50% increase from initial project cost estimates and market conditions • delayed the investment decision on the Fort Hills upgrader • revisiting Fort Hills FEED and ordering of long-lead items for the Fort Hills upgrader • received regulatory approval of the Fort Hills amended mine processes and tailings locations • Syncrude production decreased due to two planned turnarounds at two cokers, and operational upsets • received regulatory approval on MRX project in the first quarter of 2008 • received fixed bids from three international engineering firms for the MRX project • deferred making the FID for MRX due to market conditions • received regulatory approval of Fort Hills upgrader in January 2009 • reached a Syncrude royalty agreement along with its partners, with the Province of Alberta	• complete a new estimate for the Fort Hills mine costs by taking advantage of the current market softness • take delivery of some long-lead equipment for the Fort Hills upgrader and secure the asset for future re-activation • maintain spending discipline for 2009 capital commitments • position MRX for sanction once commodity and financial markets improve • continue to ramp up Syncrude Stage III expansion toward its design capacity

Link to Petro-Canada's Corporate and Strategic Priorities (continued)

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Driving for First Quartile Operation of Our Assets	· ramp up MacKay River production to hit 30,000 b/d and increase reliability to greater than 90% · commence shipping MacKay River bitumen to the Edmonton refinery after it has been upgraded into synthetic crude oil at Suncor · decrease Syncrude non-fuel unit operating costs by 10%, compared with 2007	· achieved 97% reliability at MacKay River · achieved daily throughput average of 30,000 b/d for 30 days at MacKay River · achieved record average production of 25,200 b/d at MacKay River · commenced shipping of MacKay River bitumen to Suncor for processing and subsequent shipping to the Edmonton refinery, effective January 1, 2009 · experienced higher Syncrude non-fuel unit operating costs due to lower production and higher maintenance costs	· maintain MacKay River production at 27,000 b/d and reliability above 95% · optimize the integration of MacKay River bitumen and Suncor processing through to the Edmonton refinery · work through the Syncrude joint venture owners to improve reliability and lower operating and sustaining capital costs
Continuing to Work at Being a Responsible Company	· drive for continuous improvement in safety · continue relevant and transparent engagement with key stakeholders to obtain approval for the Fort Hills upgrader and mine expansion · develop capability in managing the social issues of a temporary foreign workforce · pursue research on practical solutions for tailings management	· TRIF decreased in 2008 to 0.67, compared with 0.75 in 2007 · experienced 20 environmental regulatory exceedances in 2008, compared with six in 2007 · received regulatory approval for the Fort Hills mine amendment without a hearing · received regulatory approval for the Fort Hills upgrader in January 2009 · implemented a risk assessment to understand and mitigate the social risks related to bringing temporary foreign workers into oil sands project camps · pursuing research and industry solutions to tailings management continues to be a priority	· incorporate zero-liquid discharge into MRX facility design · implement performance measures aimed at lowering environmental regulatory exceedances · better understand how to manage the language and cultural aspects of the safety of foreign contract workers on Petro-Canada's sites

International & Offshore

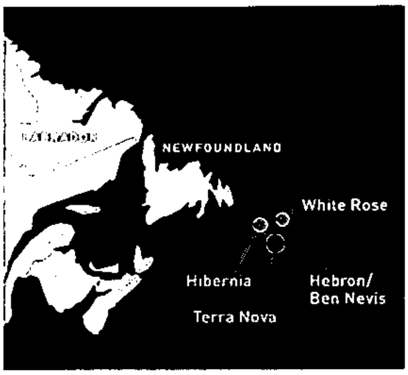
East Coast Canada

Business Summary and Strategy

Petro-Canada has a strong position in every major producing oil development off Canada's east coast. The Company holds a 20% interest in Hibernia, a 27.5% interest in White Rose[1] and a 22.7% interest in Hebron, and is the operator of Terra Nova with a 34% interest.

The East Coast Canada strategy is to deliver reliable and profitable production well into the next decade, leveraging the existing infrastructure while pursuing profitable development opportunities. Key features of the strategy include:

- delivering top quartile operating performance
- sustaining profitable production through reservoir extensions and add-ons
- pursuing high potential, near field development and exploration projects



● Operated ● Proposed/non-operated
● Non-operated

East Coast Canada Financial Results

(millions of Canadian dollars)	2008	2007	2006
Net earnings	**$ 1,368**	**$ 1,229**	**$ 934**
Cash flow from continuing operating activities	$ 1,850	$ 1,491	$ 1,129
Expenditures on property, plant and equipment and exploration	$ 276	$ 159	$ 256
Total assets	$ 2,149	$ 2,345	$ 2,465

2008 Compared with 2007

East Coast Canada contributed a record $1,368 million of net earnings, up 11% from $1,229 million in 2007. Strong realized prices and reliability were partially offset by decreased production due to natural declines, increased royalties and increased DD&A expenses.

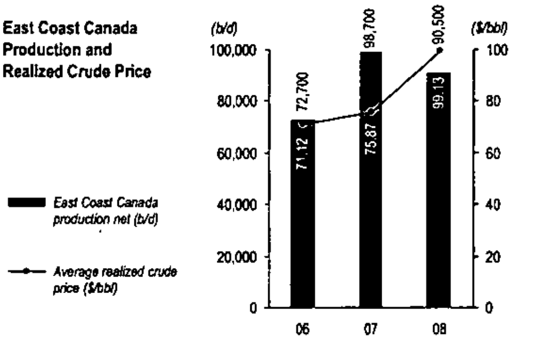
Net earnings in 2008 included $29 million of insurance proceeds related to historical mechanical failures on the Terra Nova Floating Production, Storage and Offloading (FPSO) vessel. Net earnings in 2007 included a $52 million income tax recovery and $27 million of insurance proceeds.

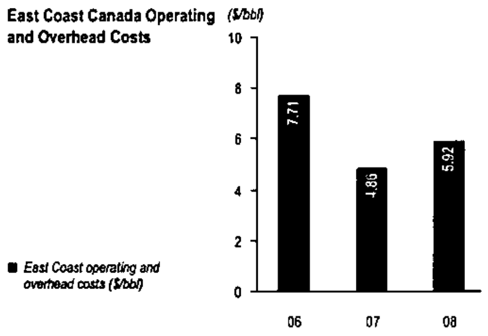
In 2008, realized crude oil prices remained strong, while production decreased. East Coast Canada realized crude prices averaged $99.13/bbl in 2008, up from $75.87/bbl in 2007. East Coast oil production averaged 90,500 b/d in 2008, down from 98,700 b/d in 2007. Decreased production reflected natural declines in all East Coast assets. Additionally, pack ice at the White Rose field in the second quarter of 2008 caused production deferments and drilling delays.

1 Petro-Canada's working interest in the White Rose Extensions is 26.125% after the Newfoundland and Labrador Energy Corporation (NALCOR) acquired its 5% working interest effective with the signing of the final project agreements in February 2009. There is no change to the White Rose 27.5% working interest for the original field development as NALCOR is not a partner.

2008 Operating Review and Strategic Initiatives

2008 Operating Review





	2008	2007	2006
Production net *(b/d)*			
Hibernia	**27,800**	26,900	35,700
Terra Nova	**34,900**	39,500	12,800
White Rose	**27,800**	32,300	24,200
Total East Coast Canada production net	**90,500**	98,700	72,700
Average realized crude price *($/bbl)*	**$ 99.13**	$ 75.87	$ 71.12
Operating and overhead costs *($/bbl)*	**$ 5.92**	$ 4.86	$ 7.71

Hibernia production averaged 139,000 b/d gross (27,800 b/d net) in 2008, up from 134,500 b/d gross (26,900 b/d net) in 2007, reflecting excellent reliability, a successful well workover campaign and the addition of two new wells. These factors offset natural reservoir declines. Hibernia had a 30-day maintenance turnaround in 2007, but no turnaround in 2008. The total royalty paid at Hibernia in 2008 equated to a rate of 5% of gross revenues.

At Terra Nova, production averaged 102,700 b/d gross (34,900 b/d net), compared with 116,200 b/d gross (39,500 b/d net) in 2007. Terra Nova production was lower in 2008 due to a planned 16-day maintenance turnaround and natural reservoir declines. In 2008, the Terra Nova FPSO operated at solid reliability of 90%, a 4% improvement over 2007. In December 2006, the Terra Nova FPSO experienced a mechanical issue in a swivel connection on the turret system that supports water injection to the reservoir. A repair was completed in December 2006 and production returned to normal rates. Performance of the water injection swivel was satisfactory throughout 2008. Contingency plans have been developed and parts have been sourced for the modification or replacement of the swivel in the event performance deteriorates. In 2008, Terra Nova achieved tier II payout, thereby increasing royalties to 42.5% of net revenues. The total royalty paid at Terra Nova in 2008 equated to a rate of 37% of net revenues.

White Rose production averaged 101,100 b/d gross (27,800 b/d net), compared with 117,500 b/d gross (32,300 b/d net) in 2007. White Rose production was impacted by pack ice in the field in the second quarter that caused production shut-ins and delayed development drilling. In 2008, White Rose achieved tier II payout, thereby increasing royalties to 30% of net revenues. The total royalty paid in 2008 equated to a rate of 27% of net revenues.

East Coast Canada operating and overhead costs averaged $5.92/bbl in 2008, up from $4.86/bbl in 2007. Unit operating costs for East Coast Canada increased as a result of lower production and higher operating expenses in the year.

2008 Strategic Initiatives

In August 2008, the Hebron partners reached an agreement with the Government of Newfoundland and Labrador on commercial terms that will allow development activities to proceed for Hebron. The partners also agreed to transfer operatorship from Chevron Canada Ltd. to ExxonMobil.

In September 2007, the Government of Newfoundland and Labrador approved the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) recommendation to permit development of the South White Rose Extension. Subsequently, the White Rose partners reached an agreement in principle with the province on fiscal and other terms for the White Rose Extensions development, incorporating the South White Rose Extension, North Amethyst and West White Rose satellite fields. This activity was concluded in December 2007 when Petro-Canada and its partners signed a formal agreement with the province for the development of these oilfields. North Amethyst will be developed initially, with first oil targeted for late 2009. The development of the West White Rose satellite is expected to follow. FEED for the North Amethyst portion of the project is complete and detailed design, procurement and fabrication are underway, with necessary long-lead equipment and drilling commitments in hand. In April 2008, the project received regulatory and government approval to proceed.

Capital expenditures for exploration and development of crude oil offshore Canada's east coast were $276 million in 2008, including $208 million related to the development of the White Rose oilfield, $45 million for Hibernia development drilling, $14 million for Terra Nova and $9 million relating to exploration drilling and preliminary Hebron activities.

Outlook

Production expectations in 2009

- East Coast production is expected to average 68,000 b/d net, reflecting 28-day planned turnarounds at both Terra Nova and White Rose, and a 21-day planned turnaround at Hibernia
- East Coast's objective is to achieve greater than 90% reliability at Terra Nova

Growth plans

- begin development drilling in the White Rose Extensions' North Amethyst satellite field and achieve first oil
- advance Hibernia Southern Extension development plan discussions with the Government of Newfoundland and Labrador to facilitate project planning and approvals
- drill an exploration well in the Jeanne d'Arc Basin on the Ballicatters prospect
- advance the Hebron project for regulatory approval in the 2010 time frame
- advance the development concept for West White Rose

Capital spending plans in 2009[1]

- capital program of approximately $530 million is planned for East Coast
  - approximately $490 million is expected to be spent primarily on advancing the White Rose Extensions developments and drilling to replace reserves at Hibernia, Terra Nova and White Rose
  - approximately $40 million is planned for investments in new growth opportunities and exploration

1 Petro-Canada will monitor energy and financial markets through 2009 and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures, as necessary.

East Coast Canada production is expected to be 68,000 b/d in 2009, compared with actual production of 90,500 b/d in 2008. The 2009 production estimate reflects natural declines and maintenance turnarounds at all three East Coast assets. The 28-day White Rose maintenance shutdown is concurrent with a 101-day shutdown of the south drill centre to tie in the White Rose Extensions' satellites. Beyond 2009, the East Coast Canada business intends to offset natural declines in the main reservoirs and sustain profitable production by adding production from reservoir extensions and satellite tie-ins. The Hebron project remains a significant resource the Company also wants to see developed.

Link to Petro-Canada's Corporate and Strategic Priorities

The East Coast Canada business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2008 and goals for 2009.

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	· advance White Rose Extensions development toward regulatory approval and FID in 2008, with first oil targeted for late 2009 · commence development drilling for the White Rose Extensions project · achieve binding formal agreements and re-establish the Hebron project team, with the goal of submitting the project for regulatory approval in the 2010 time frame · advance the Hibernia Southern Extension growth project	· achieved internal and regulatory approval for North Amethyst portion of the White Rose Extensions in 2008; on track for first oil in late 2009 · drilled a pilot well in North Amethyst for the White Rose Extensions project · signed binding formal agreements for Hebron · filed a development plan amendment application for the Hibernia Southern Extension project	· drill two development wells in the main Terra Nova field · drill exploration well in Ballicatters prospect · achieve formal agreement for Hibernia Southern Extension development · advance the target Hebron first oil date · achieve first oil at North Amethyst and finalize development concept for West White Rose
Driving for First Quartile Operation of Our Assets	· achieve and maintain greater than 90% reliability at Terra Nova · finalize Terra Nova swivel repair plans · complete 16-day turnarounds at Terra Nova and partner-operated White Rose	· achieved 90% reliability at Terra Nova · put in place all swivel contingency plans and materials, if repair/replacement is required · completed Terra Nova and White Rose turnarounds on time	· maintain greater than 90% reliability at Terra Nova and close process safety gaps · complete 28-day turnarounds at Terra Nova and White Rose, and 21-day turnaround at Hibernia · identify and implement opportunities to reduce administrative and operating costs across the business
Continuing to Work at Being a Responsible Company	· continue to reduce injuries and illnesses through implementation of Exposure Based Safety program and first aid reduction initiatives · enhance focus on process safety management · continue to implement loss containment improvement plan · continue to enhance produced water management · integrate stakeholder management process and tools and streamline with regulatory processes and requirements	· TRIF increased to 2.5, compared with 0.5 in 2007 · achieved lower combined first aids, medical aids and restricted work cases in 2008, compared with 2007 · scored 93% on TLM process safety audit · recorded one environmental regulatory exceedance, compared with zero in 2007 · improved produced water quality · trained more than 60 employees on stakeholder information management system · successfully completed an on-water oil spill countermeasure exercise · successfully completed Terra Nova operations authorization	· develop action plan to address injury frequency · develop gap closure plan and stewardship to address process safety and TLM self-assessment gap · implement continuous improvement initiatives relating to oil spill response · develop and implement GHG emissions reduction strategy and continue initiatives to improve flare management and produced water quality · support research and development initiatives that have personal safety, environmental and community benefits

International & Offshore

International

For reporting purposes, Petro-Canada has consolidated its International activities into two core areas: the North Sea (the United Kingdom (U.K.), the Netherlands and Norway sectors) and Other International areas (Libya, Syria, and offshore Trinidad and Tobago).

Business Summary and Strategy

International is concentrating on countries and regions where material positions may be built, with a particular focus on increasing the proportion of long-life assets in the portfolio. These regions include the North Sea, Libya, Syria, and Trinidad and Tobago.

Petro-Canada's International strategy capitalizes on the strengths of a mid-sized exploration and production company, which is big enough to execute large scale projects and agile enough to develop smaller projects that can still create significant value, such as the Company's concentric developments around the Triton hub in the North Sea. Key features of the International strategy are:

O Petro-Canada assets
● Petro-Canada International offices

- expanding and exploiting the existing portfolio
- targeting new growth opportunities
- executing a substantial and balanced exploration program

In 2005, Petro-Canada reached an agreement to sell the Company's mature producing assets in Syria. The sale was closed on January 31, 2006. These assets and associated results are reported as discontinued operations and excluded from continuing operations.

International Financial Results

(millions of Canadian dollars)	2008	2007	2006
Net earnings (loss) from continuing operations	**$ 1,684**	**$ 374**	**$ (206)**
Cash flow from continuing operating activities[1]	$ 2,380	$ 220	$ 840
Expenditures on property, plant and equipment and exploration from continuing operations	$ 2,115	$ 762	$ 760
Total assets from continuing operations	$ 8,277	$ 5,180	$ 6,031

1 International cash flow from continuing operating activities in 2007 was reduced by the payment of $1,145 million after-tax to settle the hedged portion of Buzzard production.

2008 Compared with 2007

International contributed a record $1,684 million of net earnings, up 350% compared with net earnings of $374 million in 2007. Higher realized prices and production were partially offset by higher exploration and DD&A expenses.

Net earnings from continuing operations in 2008 included a $227 million income tax recovery and an $88 million gain on the sale of non-core assets. Net earnings from continuing operations in 2007 included net losses on the derivative contracts associated with the hedged portion of Buzzard production of $331 million, a $30 million income tax recovery, a $9 million gain on the sale of non-core assets and $5 million in insurance proceeds from the Scott platform fire.

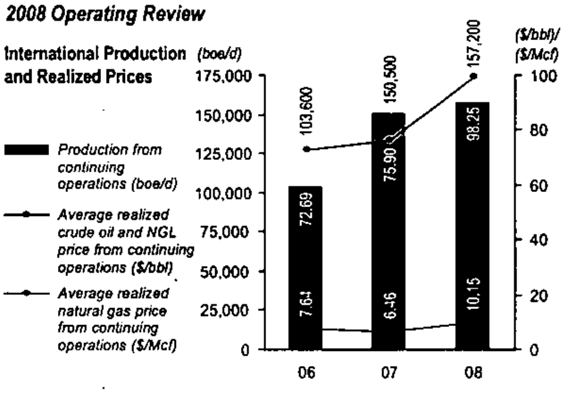
Late in 2007, the Company entered into derivative contracts to close out the hedged portion of its Buzzard production from January 1, 2008 to December 31, 2010. Under the terms of the contracts, the Company repurchased 30,688,000 bbls of Dated Brent crude oil at an average price of approximately $85.79 US/bbl, resulting in a reduction in cash flow of $1,145 million after-tax.

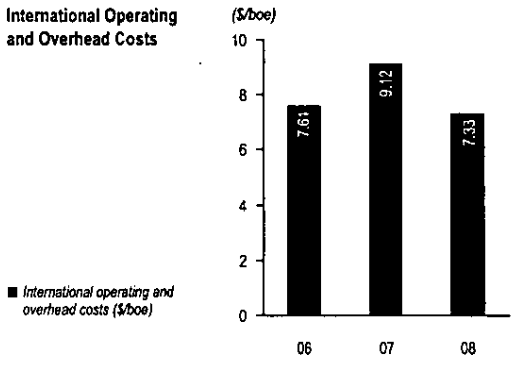
International production from continuing operations averaged 157,200 boe/d net in 2008, compared with 150,500 boe/d net in 2007. The increase was primarily due to additional North Sea production. International crude oil and NGL realized prices from continuing operations averaged $98.25/bbl and natural gas realized prices averaged $10.15/Mcf in 2008, compared with $75.90/bbl and $6.46/Mcf, respectively, in 2007. Operating and overhead costs from continuing operations averaged $7.33/boe in 2008, down 20% compared with $9.12/boe in 2007, due to lower operating expenses related to new EPSAs in Libya.

International capital expenditures from continuing operations in 2008 were $2,115 million, with $281 million directed to the North Sea region, primarily for the Buzzard enhancement project, and $1,834 million invested in Other International, primarily related to the signature bonus payment in Libya and the Ebla gas development in Syria.

2008 Operating Review and Strategic Initiatives

2008 Operating Review





		2008		2007		2006
Production from continuing operations net *(boe/d)*						
North Sea		**97,700**		91,000		43,700
Other International		**59,500**		59,500		59,900
Total International production net		**157,200**		150,500		103,600
Average realized crude oil and NGL price from continuing operations *($/bbl)*	**$**	**98.25**	$	75.90	$	72.69
Average realized natural gas price from continuing operations *($/Mcf)*	**$**	**10.15**	$	6.46	$	7.64
Operating and overhead costs from continuing operations *($/boe)*	**$**	**7.33**	$	9.12	$	7.61

North Sea

Petro-Canada's North Sea production averaged 97,700 boe/d net in 2008, compared with 91,000 boe/d net in 2007. Additional production from Buzzard and Saxon and full-year production from De Ruyter and L5b-C were partially offset by natural declines and problems with two producing wells in the Triton area. North Sea crude oil and NGL realized prices averaged $97.76/bbl and natural gas averaged $12.15/Mcf in 2008, compared with $75.12/bbl and $7.94/Mcf, respectively, in 2007.

During 2008, Petro-Canada continued to leverage its existing infrastructure through concentric development near core areas and through new discoveries.

In the U.K. sector of the North Sea, the Buzzard development, in which the Company has a 29.9% interest, achieved first oil in January 2007 and ramped up to peak production of 220,000 boe/d gross (65,700 boe/d net) in July 2007.

Sections of the Buzzard field contain higher than expected levels of hydrogen sulphide. In order to meet the crude quality requirements of the Forties pipeline system, the partners are installing additional sulphur handling equipment on the facility. This work is on schedule for installation in late 2010 or early 2011.

U.K. exploration success continued in 2008 with the non-operated Pink discovery, located in Block 20/1 North, where the non-operated Golden Eagle discovery was drilled in late 2006. Together with its joint venture partners, the Company is evaluating more exploration opportunities in the immediate area, with a view to optimizing the development plan for the discovered resources. Petro-Canada holds a 25% working interest in the Golden Eagle discovery and a 33% interest in the Pink discovery.

In the Netherlands sector of the North Sea, oil production comes from the Petro-Canada operated Hanze and De Ruyter platforms. The Company has a 45% working interest in Hanze and a 54.07% working interest in De Ruyter. At a current combined gross production rate of approximately 25,000 boe/d, these assets were the largest source of domestic oil in the Netherlands in 2008.

The major source of the Company's natural gas production in the Netherlands is from the L5b-L8b non-operated natural gas area (Petro-Canada working interest of approximately 30%), with net production of approximately 33 MMcf/d.

In the Netherlands sector of the North Sea, the Company, as operator with a 50% working interest, drilled a successful exploration well in 2008: van Ghent. The Company drilled two successful exploration wells in 2007, van Nes and van Brakel, as operator with a 50% and 60% working interest, respectively. Both van Nes and van Brakel were suspended as gas discoveries. As all three wells are in the vicinity of the De Ruyter development, the potential to tie these wells back to De Ruyter is being assessed.

In the third quarter of 2008, the Company completed a sales and purchase agreement with Bayerngas Norge AS for the sale of all the Company's interests in Denmark for net proceeds of $140 million, resulting in a $107 million ($82 million after-tax) gain on the sale of these assets. The sale of all of Petro-Canada's interests in Denmark is consistent with the International & Offshore business unit strategy to optimize the portfolio by reducing participation in countries where the Company cannot foresee developing a material position.

In 2008, the Company was awarded four additional production licences in the 2007 Awards in Predefined Areas round in Norway. Petro-Canada is operator of five of the 17 licences in Norway.

Other International

Libya

Petro-Canada is one of the larger producers in Libya through its 50% interest in Harouge Oil Operations, a joint venture with the NOC. In 2008, Petro-Canada's production from continuing operations in Libya averaged 48,800 boe/d net, up 2% from 47,700 boe/d net in 2007. In early January 2009, the NOC advised the Company that production from Petro-Canada's Libya EPSAs will be limited to 85,000 b/d gross (42,500 b/d net) due to the quota agreed to by OPEC producers in December 2008.

Libyan crude oil and NGL realized prices averaged $101.97/bbl in 2008, compared with $77.26/bbl in 2007. Petro-Canada's production is currently sold on contract to the NOC. In 2008, 12 development wells were completed in the producing fields in Libya, consisting of 11 production wells and one injection well. Additionally, one appraisal well was drilled. A further five development wells were being drilled at year end.

Petro-Canada is the operator, with a 50% working interest, of Block 137 in the Sirte Basin. In 2008, the Company completed 2D and 3D seismic acquisitions and is evaluating the data in preparation for drilling an exploration well.

In June 2008, Petro-Canada signed six new EPSAs with the Libya NOC to replace its existing concession agreements. The new EPSAs were ratified as of the signing, with an effective date of January 1, 2008. 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 new EPSAs will run for 30 years and enable the Company and the NOC to jointly design and implement the redevelopment of the existing fields in the Sirte Basin. Petro-Canada and the NOC will each pay one-half of development expenditures, which are expected to total up to $7 billion US gross over the term of the licences. It is expected that the investment will double existing production to 200,000 boe/d gross (100,000 boe/d net).

Under the new agreements, the Company is the exploration operator and has committed to fully fund an exploration program at an estimated cost of $460 million US over a five-year period. Petro-Canada has started to acquire 3D seismic over the new EPSA acreage and expects to start exploration drilling in 2009.

Following the signing of the new EPSAs, work began immediately on building the management, technical and administration staff necessary for the successful execution of the new exploration and development programs. By the end of 2008, four seismic crews had been deployed in the Sirte Basin and planning was well underway to begin exploration drilling in the second half of 2009. In the redevelopment program, priority is being given to the Amal field, where a comprehensive field development plan is expected to be completed in 2009. Work is also underway to identify opportunities to increase production in the near term through well reactivations and workovers.

Syria

In 2008, the Company completed FEED and undertook 2D and 3D seismic operations for the Ebla gas project. The Ebla gas project is expected to produce an estimated 80 MMcf/d of natural gas from the Ash Shaer and Cherrife natural gas fields, with first gas anticipated in 2010. The EPC contract for the project's production facilities was awarded and construction was 50% complete at the end of 2008. The Ebla gas project progressed on time and on budget.

The Company believes there is significant upside potential in the Ebla gas fields. A 3D seismic survey program to map the known reservoir and new structures over 900 square kilometres is underway, and is expected to be completed during the second quarter of 2009. Two drilling rigs are now working on the Ebla gas project and first gas is targeted for mid-2010.

The Company is building an exploration position in Syria by securing Block II, where two exploration wells were drilled in 2008, and by continuing negotiations on two further exploration blocks.

Trinidad and Tobago

In 2008, Petro-Canada's share of Trinidad and Tobago offshore production averaged 64 MMcf/d net, down from 71 MMcf/d net in 2007. Decreased production reflected additional maintenance at the Atlantic LNG plant, rebalancing of mutual aid production among producers to the Atlantic LNG plant and several brief shutdowns of the North Coast Marine Area (NCMA-1) asset to prepare for the startup of the new Poinsettia field. Trinidad and Tobago realized prices for natural gas averaged $7.15/Mcf in 2008, compared with $4.34/Mcf in 2007.

The Company holds a 17.3% working interest in the NCMA-1 offshore natural gas development project, where first gas was achieved in late 2006. Development of the Poinsettia field, with a platform and pipeline tie-back to the Hibiscus platform, was carried out on schedule during 2008. First gas is planned for the first quarter of 2009 from one subsea well, and six platform wells will commence drilling in the third quarter of 2009.

In 2008, Petro-Canada completed its eight-well exploration program in Block 22 and Block 1a/1b, which yielded four material discoveries (two on Block 22 and two on Block 1a). The Company expects to develop a strategy to commercialize these discoveries in 2009.

Other

In July 2008, Petro-Canada converted its existing reconnaissance licence in southern Morocco to an exploration permit. The Company's partners in the exploration licence include German company RWE and the Moroccan National Office of Hydrocarbons.

Outlook

Production expectations in 2009

- North Sea oil and gas production to average 85,000 boe/d net
- Other International oil and gas production to average 52,000 boe/d net

Growth plans

- advance the redevelopment and exploration programs in Libya
- achieve scheduled milestones for the Syria Ebla gas project
- develop a commercialization strategy for discoveries in Trinidad and Tobago
- carry out a successful exploration program

Capital spending plans in 2009[1]

- capital program of approximately $1,270 million is planned for International
  - approximately $670 million, primarily for new growth projects in Syria and Libya
  - approximately $470 million for reserves replacement spending in core areas, primarily at Buzzard, Guillemot West and Saxon
  - approximately $130 million for exploration

1 Petro-Canada will monitor energy and financial markets through 2009 and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures, as necessary.

International production from continuing operations is expected to be 137,000 boe/d net in 2009, lower than production levels of 157,200 boe/d net in 2008. Lower expected production in 2009 reflects a 28-day planned turnaround at Buzzard, announced OPEC production target cuts and natural declines in several fields.

Link to Petro-Canada's Corporate and Strategic Priorities

The International business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2008 and goals for 2009.

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	· evaluate 2007 exploration results and deliver 2008 exploration program · develop a transition plan for the Libya Concession Development project · develop a detailed exploration program in Libya · award EPC contract for Syria Ebla gas project and finalize commercial agreements · spud first well for the Syria Ebla gas project · evaluate opportunities to commercialize Trinidad and Tobago gas discoveries, subject to exploration results	· drilled 13 exploration wells, with nine wells completed as discoveries, four wells abandoned as dry holes and one well still drilling at year end · signed six new EPSAs with the Libya NOC, adding reserves and extending terms by an expected 30 years with improved commercial terms · commenced 3D seismic program in Libya · completed 50% of Syria Ebla gas project · commenced seismic and development drilling on the Syria Ebla gas project · participated in four gas discoveries in Trinidad and Tobago and began study of commercialization options	· continue appraisal and development planning for the U.K. and the Netherlands exploration discoveries · drill up to three exploration wells in the U.K. and Norway depending on rig availability · continue Libya exploration 3D seismic program and start exploration drilling program · prepare and submit redevelopment plans for the Libya Amal field and pursue early production gains across the new contract areas · complete the Syria Ebla seismic program and continue development drilling and construction of the Syria Ebla gas plant with a first gas target of mid-2010 · develop appraisal and commercialization strategies for the Trinidad and Tobago discoveries
Driving for First Quartile Operation of Our Assets	· maintain excellent production efficiency at the Petro-Canada operated De Ruyter and Hanze platforms · deliver plateau level production at Buzzard while the enhancement program is implemented	· delivered 97% reliability at both De Ruyter and Hanze facilities · Buzzard achieved average production of 205,000 boe/d gross (61,300 boe/d net), in line with plateau production expectations	· maintain greater than 90% reliability at Hanze and De Ruyter and drill a Hanze Pliocene development well · develop and implement Triton de-bottlenecking and reliability improvement plans · identify and implement opportunities to reduce administrative and operating costs across the business
Continuing to Work at Being a Responsible Company	· continue to work with contractors to reduce injuries and illnesses · continue to improve TLM systems and processes in Libya · complete the EIA for the Ebla gas project in Syria · continue to develop stakeholder management processes to maintain positive outcomes with key stakeholders	· TRIF was 0.62, a decrease of 56% compared with 1.42 in 2007 · held Zero-Harm conference for major contractors in the Netherlands and Syria · experienced one environmental regulatory exceedance, compared with zero in 2007 · established fully capable Environment Safety and Social Responsibility (ES&SR) organizations in Libya and Syria · completed the EIA for the Syria Ebla gas project · addressed local stakeholder concerns in Trinidad and Tobago (impact on fishing activities) and in Syria (feeding grounds of Northern Bald Ibis)	· focus on contractor management to improve safety performance, with particular emphasis in Syria and Libya on land transport safety · monitor water consumption required to support Syria and Libya activities and identify opportunities to reduce water use · continue stakeholder engagement training in Syria and Libya and support implementation of processes and tools

Discontinued Operations

On January 31, 2006, Petro-Canada completed the sale of the Company's producing assets in Syria to a joint venture of companies owned by India's Oil and Natural Gas Corporation Limited and the China National Petroleum Corporation for net proceeds of $640 million. The sale resulted in a gain on disposal of $134 million recorded in the first quarter of 2006. This sale aligned with Petro-Canada's strategy to increase the proportion of long-life and operated assets within its portfolio. Petro-Canada's activities in Syria remain part of the Other International producing region, with an active exploration program in Block II and the addition of the Ebla gas project in Syria during 2006.

Producing assets in Syria are presented as discontinued operations in the Consolidated Financial Statements. Petro-Canada's net earnings from discontinued operations in 2006 were $152 million and included a gain on disposal of $134 million. Summary information is presented below. Additional information concerning Petro-Canada's discontinued operations can be found in Note 5 to the Consolidated Financial Statements.

Discontinued Financial Results

(millions of Canadian dollars, unless otherwise noted)		**2008**		2007		2006
Net earnings from discontinued operations	$	–	$	–	$	152
Cash flow from discontinued operating activities	$	–	$	–	$	15
Expenditures on property, plant and equipment and exploration	$	–	$	–	$	1
Total assets	$	–	$	–	$	–
Total volumes *(boe/d)*						
– net before royalties		–		–		5,500
– net after royalties		–		–		1,400
Average realized crude oil and NGL price *($/bbl)*	$	–	$	–	$	71.84
Average realized natural gas price *($/Mcf)*	$	–	$	–	$	7.94

Upstream Production

2008 Compared with 2007

In 2008, Petro-Canada's production of crude oil, NGL and natural gas averaged 418,000 boe/d net, flat compared with 2007.

2008 Average Daily Production Volumes Net	North American Natural Gas	Oil Sands	*International & Offshore* East Coast Canada	*International & Offshore* International	Total
Crude oil, NGL and bitumen *(b/d)*					
– net before royalties	**13,100**	**25,200**	**90,500**	**137,200**	**266,000**
– net after royalties	**9,900**	**25,000**	**68,600**	**119,400**	**222,900**
Synthetic crude oil *(b/d)*					
– net before royalties	**-**	**34,700**	**-**	**-**	**34,700**
– net after royalties	**-**	**29,700**	**-**	**-**	**29,700**
Natural gas *(MMcf/d)*					
– net before royalties	**586**	**-**	**-**	**120**	**706**
– net after royalties	**466**	**-**	**-**	**119**	**585**
Total volumes *(boe/d)*					
– net before royalties	**110,800**	**59,900**	**90,500**	**157,200**	**418,400**
– net after royalties	**87,600**	**54,700**	**68,600**	**139,200**	**350,100**

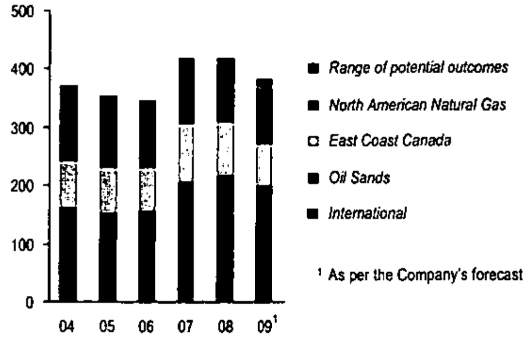
2007 Average Daily Production Volumes Net	North American Natural Gas	Oil Sands	*International & Offshore* East Coast Canada	*International & Offshore* International	Total
Crude oil, NGL and bitumen *(b/d)*					
– net before royalties	12,500	20,300	98,700	129,000	260,500
– net after royalties	9,500	20,100	84,400	124,700	238,700
Synthetic crude oil *(b/d)*					
– net before royalties	–	36,600	–	–	36,600
– net after royalties	–	31,100	–	–	31,100
Natural gas *(MMcf/d)*					
– net before royalties	599	–	–	129	728
– net after royalties	471	–	–	123	594
Total volumes *(boe/d)*					
– net before royalties	112,300	56,900	98,700	150,500	418,400
– net after royalties	88,000	51,200	84,400	145,200	368,800

2009 Production Outlook

In 2008, production of crude oil, NGL and natural gas averaged 418,000 boe/d net, which was at the high end of the Company's 2008 guidance. Upstream production is expected to decrease in 2009, due to large facility turnarounds in East Coast Canada and International, natural declines in East Coast Canada and Western Canada, cutbacks to 2009 planned capital expenditures that affect near-term production and OPEC quota restraints in Libya. Offsetting these decreases is the expectation of higher Oil Sands production. Production is expected to average in the range of 345,000 boe/d to 385,000 boe/d in 2009. The production guidance range was expanded to reflect market uncertainty in the current environment, the potential impact on near-term production if low commodity prices persist or worsen, and whether further reductions to capital expenditures are needed.

Production from Continuing Operations

(thousands of barrels of oil equivalent – Mboe/d, net before royalties)



[1] As per the Company's forecast

Factors that may impact production during 2009 include reservoir performance, drilling results, facility reliability, changes in OPEC production quotas and the successful execution of planned turnarounds.

Consolidated Production Net

(thousands of boe/d)	2008 Outlook(+/-) As at July 24, 2008	2008 Actual	**2009 Outlook (+/-) As at January 29, 2009**
North American Natural Gas			
Natural gas	94	98	**81**
Liquids	12	13	**14**
Oil Sands			
Syncrude	35	35	**38**
MacKay River	25	25	**27**
International & Offshore			
East Coast Canada	87	90	**68**
International			
North Sea	94	98	**85**
Other International	58	59	**52**
Total	400 – 420	418	**345 – 385**

Reserves Summary

The Company's reserves data and reserves quantities are determined by Petro-Canada's staff of qualified reserves evaluators using corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform with the U.S. Securities and Exchange Commission (SEC) standards, as well as with the requirements in Canada, and the Association of Professional Engineers, Geologists and Geophysicists of Alberta's Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure. Petro-Canada also employs independent third parties to evaluate, audit and/or review its reserves processes and estimates. In 2008, 49% of North American (excluding Oil Sands) and 60% of International proved reserves were assessed by independent reserves evaluators. Also in 2008, 100% of Oil Sands bitumen proved reserves were audited and 100% of Oil Sands mining proved reserves were reviewed by independent reserves evaluators. The independent reserves evaluators concluded that the Company's year-end reserves estimates were reasonable.

Petro-Canada's proved reserves table that conforms to SEC standards for Oil and Gas activities can be found on page 104.

The following table and the accompanying narrative do not conform to SEC standards and are for supplemental general information. The reporting of working interest reserves before royalties and MMboe do not conform to SEC standards.

December 31, 2008 Consolidated Reserves – for Oil and Gas Activities	**Proved liquids**	**Proved gas**	**2008 Proved reserves additions liquids[1]**	**2008 Proved reserves additions gas[1]**	**Proved[2]**	**2008 Proved reserves additions[1]**
(working interest before royalties)	*(MMbbls)*	*(Billion cubic feet – Bcf)*	*(MMbbls)*	*(Bcf)*	*(MMboe)*	*(MMboe)*
North American Natural Gas	42	1,274	2	9	254	3
Oil Sands[3]	258	–	(9)	–	258	(9)
International & Offshore						
East Coast Canada	81	–	14	–	81	14
International	290	220	89	(16)	327	87
Total	**671**	**1,494**	**96**	**(7)**	**920**	**95**
Production net	**(97)**	**(258)**			**(140)**	

1 Proved reserves additions are the sum of revisions of previous estimates, net purchases/sales, and discoveries, extensions and improved recovery.

2 At year-end 2008, 54% of proved reserves were classified as proved developed reserves. Of the total proved undeveloped reserves, 96% were associated with large projects currently producing or under active development, including Buzzard, Syncrude, MacKay River, Hibernia, Terra Nova, and Trinidad and Tobago natural gas.

3 Oil Sands proved reserves excluded reserves from Syncrude, which is considered a mining activity by the SEC.

At year-end 2008, the Company had 920 MMboe of proved reserves from oil and gas activities, compared with 965 MMboe at the end of 2007.

December 31, 2008 Reserves – for Syncrude Mining Operation	**Proved liquids**	**2008 Proved reserves additions liquids[1]**
(working interest before royalties)	*(MMbbls)*	*(MMbbls)*
Reserves of synthetic crude oil	366	29
Production net	(13)	

1 Proved reserves additions are the sum of revisions of previous estimates, net purchases/sales, and discoveries, extensions and improved recovery.

At year-end 2008, the Company had 366 MMbbls of proved reserves from Oil Sands mining operations, compared with 350 MMbbls at year-end 2007.

The following table and the accompanying narrative do not conform to SEC standards and are for supplemental general information. Working interest reserves before royalties, MMboe and combining oil and gas and oil sands mining activities do not conform to SEC standards.

December 31, 2008 Consolidated Reserves – for Oil and Gas and Oil Sands Mining Activities *(working interest before royalties)*	**Proved liquids** *(MMbbls)*	**Proved gas** *(Bcf)*	**2008 Proved reserves additions liquids[1]** *(MMbbls)*	**2008 Proved reserves additions gas[1]** *(Bcf)*	**Proved[2]** *(MMboe)*	**2008 Proved reserves additions[1]** *(MMboe)*
North American Natural Gas	42	1,274	2	9	254	3
Oil Sands[3]	624	–	20	–	624	20
International & Offshore						
East Coast Canada	81	–	14	–	81	14
International	290	220	89	(16)	327	87
Total	**1,037**	**1,494**	**125**	**(7)**	**1,286**	**124**
Production net	**(110)**	**(258)**			**(153)**	

1 Proved reserves additions are the sum of revisions of previous estimates, net purchases/sales, and discoveries, extensions and improved recovery.

2 At year-end 2008, 54% of proved reserves were classified as proved developed reserves. Of the total proved undeveloped reserves, 96% were associated with large projects currently producing or under active development, including Buzzard, Syncrude, MacKay River, Hibernia, Terra Nova, and Trinidad and Tobago natural gas.

3 Oil Sands proved reserves included reserves from Syncrude and MacKay River.

Petro-Canada's objective is to replace reserves over time through exploration, development and acquisition. The Company believes that, due to the specific nature of its upstream portfolio and attributes of its probable reserves, the combination of proved plus probable reserves provides the best perspective of Petro-Canada's reserves.

In 2008, proved reserves additions totalled 124 MMboe, excluding 2008 production of 153 MMboe net. As a result, total proved reserves decreased to 1,286 MMboe at year-end 2008, compared with 1,315 MMboe at year-end 2007. This decrease included a (37) MMboe revision associated with the lower 2008 year-end crude oil prices, compared with 2007 year-end prices. The majority of the lower year-end prices negatively impacted the North American Natural Gas and International business units and are reflected in the volume numbers listed below.

The North American Natural Gas business added 3 MMboe of proved reserves additions in 2008. Reserves additions were due to exploration and development activity, partially offset by technical revisions related to reservoir performance and the year-end price impact.

In 2008, 20 MMbbls of proved reserves were added in Oil Sands.[1] At Syncrude, 29 MMbbls were added to proved reserves as a result of a planned mine extension. At MacKay River, delineation drilling resulted in a revision of (9) MMbbls of proved reserves.

In East Coast Canada, a total of 14 MMbbls were added to proved reserves during 2008, due to ongoing development well drilling and production performance at White Rose, Terra Nova and Hibernia.

International proved reserves increased by 87 MMboe in 2008, due primarily to development activity at Buzzard and the contract extensions in Libya, partially offset by the year-end price impact.

Further detail on Petro-Canada's reserves is provided in the reserves table at the end of this report (see pages 103 to 107).

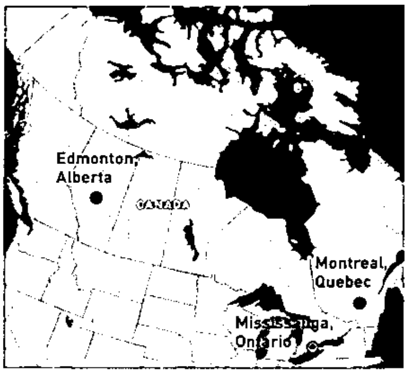
1 Oil Sands proved reserves include reserves from Syncrude and MacKay River. Syncrude is an oil sands mining operation. Oil sands mining is not an oil and gas activity as defined by the SEC. The oil sands mining proved reserves are estimated in accordance with the SEC Industry Guide 7.

Downstream

Business Summary and Strategy

Petro-Canada has the second largest downstream business and is the "brand of choice" in Canada. In 2008, Petro-Canada accounted for approximately 13% of the total refining capacity in Canada and about 15% of total petroleum products sold in Canada.

Downstream operations include two refineries – one in Edmonton and one in Montreal – with a total daily rated capacity of 40,500 cubic metres/day (m^3/d) (255,000 b/d), a lubricants plant that is the largest producer of lubricant-base stocks in Canada, a network of 1,323 retail service stations, Canada's largest national commercial road transport network of 233 locations and a robust bulk fuel sales channel.



The strategy in the Downstream business is to increase the profitability of the base business through effective capital investment and disciplined management of controllable factors. The Downstream business goal is to deliver superior returns and growth, including a 12% return on capital employed (ROCE) based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance in all areas
- managing and reducing costs, with a specific focus on reducing feedstock costs
- growing revenue

The trend toward increased heavy crude production globally has resulted in an increased need for refining capacity that can process this feedstock. As a result, Petro-Canada converted the conventional crude oil train at its Edmonton refinery to refine oil sands-based feedstock, and the Company is considering construction of a 25,000 b/d coker at its Montreal refinery. An investment decision on a new coker at the Montreal refinery is on hold, pending suitable project costs and return to a more stable financial market.

Downstream Financial Results

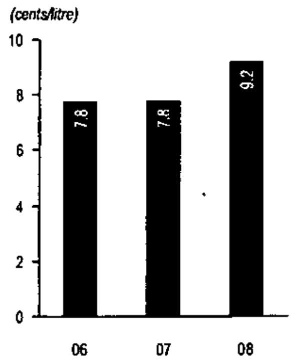
(millions of Canadian dollars)	**2008**	2007	2006
Net earnings	**$ –**	**$ 629**	**$ 473**
Cash flow from continuing operating activities	**$ 464**	$ 994	$ 835
Expenditures on property, plant and equipment	**$ 1,834**	$ 1,396	$ 1,229
Total assets	**$ 10,057**	$ 7,989	$ 6,649

2008 Compared with 2007

Downstream contributed net earnings of $nil in 2008, down significantly from $629 million in 2007. Net earnings were impacted by a weaker business environment for gasoline cracking margins, a change in inventory accounting methodology and lower refinery yields predominantly at Edmonton due to planned turnaround activity to tie in and ramp up the new RCP units and unplanned operational upsets.

Downstream Operating, Marketing and General Costs

■ *Downstream operating, marketing and general costs (cents/litre)*



Net earnings in 2008 included an $8 million insurance premium surcharge, partially offset by a $4 million gain on the sale of assets and a $2 million income tax recovery. Net earnings in 2007 included a $34 million income tax recovery and a $7 million gain on the sale of assets.

In 2008, Refining and Supply had a net loss of $205 million, compared with net earnings of $446 million in 2007. The net loss in 2008 reflected lower gasoline cracking margins, the negative impact from declining crude oil feedstock costs while using a FIFO inventory valuation methodology and lower refinery yields predominantly at Edmonton due to planned turnaround activity to tie in the new RCP units and unplanned upsets.

Total sales of refined products decreased by 1% compared with 2007. The decreased volumes reflected lower Marketing sales, which were impacted by a slowdown in demand and reduced low-margin Refinery and Supply sales, partially offset by higher lubricants sales volumes.

In 2008, Marketing contributed net earnings of $205 million, compared with $183 million in 2007. Improved margins were partially offset by increased operating expenses for distribution and costs related to higher fuel prices and lower volume.

Total Downstream operating, marketing, and G&A unit costs of 9.2 cents/litre in 2008 were up compared with 2007. The increase mainly reflected higher maintenance and repair activity, planned turnarounds and higher salaries and wage costs.

2008 Operating Review and Strategic Initiatives

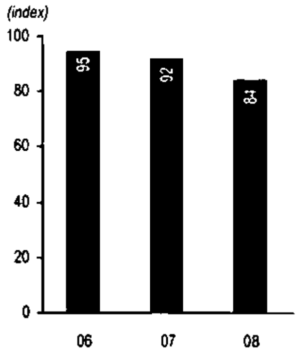
Petro-Canada is well positioned with the supply capability to optimize profitability within a range of future business environment scenarios.

Refining and Supply

In 2008, the business processed an average of 36,000 m^3/d of crude oil, down from 40,100 m^3/d in 2007. The overall utilization rate at Petro-Canada's two refineries averaged 89% in 2008, down from 99% in 2007. The decrease was largely due to planned turnaround activity associated with the Edmonton RCP and subsequent ramp up activity, and in part to unplanned outages at the Edmonton refinery in the third quarter.

Refinery Reliability Index

■ *Refinery Reliability Index*



Overall plant reliability is a critical component of success in the refining business. In 2008, the overall refinery reliability index was 84. This is down from 2007 due to unplanned outages at the Edmonton refinery in the third quarter.

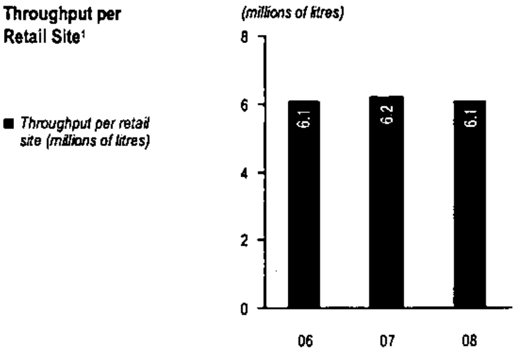
At the Edmonton refinery, construction was completed on the RCP to upgrade and refine oil sands-based feedstock. This project came on-stream in the fourth quarter of 2008. At its Montreal refinery, the Company furthered work to evaluate the feasibility of adding a 25,000 b/d coker to the refinery. An investment decision on a new coker at the Montreal refinery is on hold, pending suitable project costs and return to a more stable financial market.

Marketing

Total Downstream sales decreased to an average 52,400 m^3/d in 2008, compared with 53,300 m^3/d in 2007. Decreased volumes reflect lower Marketing sales impacted by a slowdown in demand and reduced low-margin refinery and supply sales, partially offset by higher lubricants sales volumes.

In the retail business, Petro-Canada led the industry in key urban market metrics, focusing on selective representation and site development and generating high site throughputs. Within the Company's network, annual sales averaged 6.1 million litres per site. In 2008, the Company also continued to expand its independent retail network.

Throughput per Retail Site[1]



[1] Excludes Petro-Canada branded sites operated by independent dealers.

Petro-Canada continued to expand its non-petroleum revenue base. This included advancing previously launched product offerings and implementing new products, such as the Fuel Savings Reward Card and car wash Seasons' Passes. The business continued to expand the Neighbours fresh food offering and the industry-leading GLIDE Autowash offering. Despite a challenging business environment in 2008, year-over-year convenience store sales grew by 1% while same-store sales declined by 1%, compared with 2007.

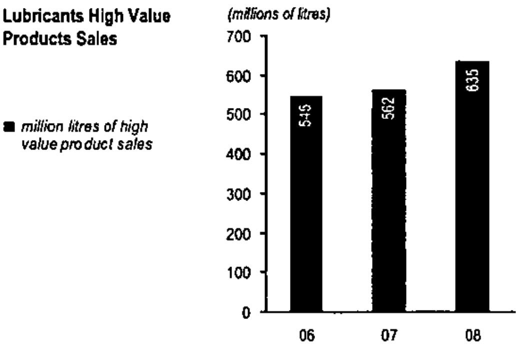
In 2008, the wholesale PETRO-PASS network, which includes 233 truck stop facilities, continued to be the leading national marketer of fuel in the commercial road transport segment in Canada. This distribution network was upgraded during the year.

Lubricants

Overall sales of lubricants totalled 850 million litres in 2008, an increase of 9% compared with sales volumes of 778 million litres in 2007. The increase in sales volumes was primarily due to higher process fluid, white oil, base oil and commercial and industrial product sales, partially offset by lower wax and automotive product sales.

Sales into high value product segments grew to 635 million litres, a 13% increase compared with 2007. High value product segments now represent 75% of total sales. Over the past five years, sales of high value products have grown by approximately 26%.

Lubricants High Value Products Sales



Lubricants is positioned for profitable future growth as tougher product performance and environmental standards increase global demand for higher quality base oils and finished products like those produced at the Mississauga, Ontario lubricants plant. In 2008, Lubricants advanced product development and commercialization of its new eco-friendly lawn care product lines, receiving U.S. National Environmental Protection Agency approval for sales into the U.S. market. Product launch plans are currently underway. Also in 2008, Lubricants obtained a business licence to begin direct sales into the China market.

Downstream capital expenditure of $1,834 million in 2008 included $1,651 million in Refining and Supply, predominantly associated with the Edmonton RCP of $1,198 million, $156 million in Sales and Marketing and $27 million in Lubricants.

Outlook

Growth plans

- increase service station network effectiveness, with a focus on increasing non-petroleum revenue
- build wholesale volumes primarily through the commercial road transport and bulk fuels sales channels
- increase sales of high quality, higher value lubricants through expansion into new markets and introduction of new products

Capital spending plans in 2009[1]

- capital program of approximately $560 million is planned for the Downstream
  - approximately $325 million focused on new growth projects, such as the possible Montreal coker
  - approximately $105 million to enhance existing operations, including reliability and safety improvements at Downstream facilities and site enhancement within the retail and wholesale networks
  - approximately $60 million to improve profitability in the base business, including continued development of the retail and wholesale network and a number of refinery improvement programs
  - approximately $70 million for regulatory compliance projects and safety upgrade programs

1 Petro-Canada will monitor energy and financial markets through 2009 and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures, as necessary.

Downstream investment is focused on growth and improving base business profitability. The Edmonton RCP project is expected to add earnings and cash flow with the first full year in 2009.

Based on the current mid-cycle business environment, the Downstream business delivered a mid-cycle ROCE of just under 10% in 2008. Over time, it is anticipated that improvement in the base business and growth projects, including the Edmonton RCP, will help drive the mid-cycle ROCE to 12%.

Link to Petro-Canada's Corporate and Strategic Priorities

The Downstream business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2008 and goals for 2009.

PRIORITY	2008 GOALS	2008 RESULTS	2009 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	· advance Montreal coker, with FID expected in the second quarter of 2008 · complete Edmonton RCP for startup in the fourth quarter of 2008 · continue to invest in smaller scale refinery yield and reliability improvement projects · selectively invest in retail and wholesale assets	· completed FEED for proposed 25,000 b/d Montreal coker; FID for project was delayed due to market conditions · completed construction of the Edmonton RCP and started up in the fourth quarter · invested $41 million in smaller scale refinery yield and reliability improvement projects · made selective investments in retail and wholesale assets	· review costs for Montreal coker project and position it for sanction when commodity and financial markets improve · realize value of the Edmonton RCP investment · prudently manage refinery capital expenditure spending consistent with economic conditions · selectively invest in retail and wholesale assets
Driving for First Quartile Operation of Our Assets	· continue to focus on safety and refinery reliability, with increased focus on process safety · reduce feedstock costs · increase retail non-petroleum revenue · grow high value lubricants sales volumes	· achieved a combined reliability index of 84 at the Company's two refineries · began processing lower cost oil sands-based feedstock at completed Edmonton RCP · grew convenience store sales by 1%, while same-store sales declined by 1% compared with 2007 · increased high value lubricants sales volumes by 13%	· continue to focus on personal and process safety, refinery reliability and environmental responsibility · reduce feedstock costs · increase retail non-petroleum revenue · grow high value lubricants sales volumes
Continuing to Work at Being a Responsible Company	· maintain focus on TRIF and regulatory compliance exceedances · assess highest risk retail sites for safety and security enhancements · assess water use at retail and wholesale facilities and review current management activities in high risk areas	· TRIF decreased to 0.60, compared with 0.64 in 2007 · recorded 13 environmental regulatory exceedances, compared with 12 in 2007 · completed safety and security assessments at retail sites and implemented upgrades based on priority profile · assessed water quality risks and identified highest risk retail and wholesale facilities and developed water quality management plans based on corporate water principles	· execute drinking water management plans for high risk wholesale and retail facilities and develop criteria to audit success · employ Life-Cycle Value Assessment (LCVA) to help inform decisions regarding waste management and minimization at refineries · maintain focus on energy efficiency and GHG mitigation opportunities and establish a baseline for new Edmonton refinery configuration · maintain focus on TRIF and integrate new measures related to process safety activities

Shared Services and Eliminations

Shared Services and Eliminations includes investment income, interest expense, foreign currency translation and general corporate revenue and expenses.

Shared Services and Eliminations Financial Results

(millions of Canadian dollars)		**2008**		2007		2006
Net loss	**$**	**(596)**	**$**	**(6)**	**$**	**(263)**
Cash flow from (used in) continuing operating activities	**$**	**151**	$	(603)	$	(346)

2008 Compared with 2007

Shared Services and Eliminations recorded a net loss of $596 million in 2008, compared with a loss of $6 million in 2007.

The 2008 net loss included a $606 million foreign currency translation gain on long-term debt, a $126 million recovery related to the mark-to-market valuation of stock-based compensation and an $18 million income tax recovery. The 2007 net loss included a $208 million foreign currency translation gain on long-term debt, a $54 million charge related to the mark-to-market valuation of stock-based compensation and a $5 million income tax recovery.

Fourth Quarter 2008

For a discussion and analysis of the Company's fourth quarter 2008 performance and results, see Petro-Canada's MD&A for that period, which is incorporated herein, by reference.

Financial Reporting

Critical Accounting Estimates

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's critical accounting policies and any significant changes thereto. A summary of the significant accounting policies used by Petro-Canada can be found in Note 1 to the 2008 Consolidated Financial Statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of significant estimates or assumptions.

Property, Plant and Equipment/Depreciation, Depletion and Amortization

Investments in exploration and development activities, including *in situ* oil sands activities, are accounted for under the successful efforts method. Under this method, the acquisition costs of unproved acreage; the costs of exploratory wells pending determination of proved reserves; and the costs of wells, which are assigned proved reserves and development costs, including costs of all wells, are capitalized. The cost of unsuccessful wells and all other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Acquisition, exploration and development of oil sands mining activities are capitalized when costs are recoverable and directly result in an identifiable future benefit. Capitalized costs of oil and gas producing properties, including *in situ* oil sands properties and oil sands mining properties, are depreciated and depleted using the unit of production method based upon estimated reserves (see Estimated Oil and Gas Reserves discussion on page 59). Reserves estimates can have a significant impact on net earnings, because they are a key component in the calculation of depreciation and depletion related to the capitalized costs of property, plant and equipment. A revision in reserves estimates could result in a higher or lower depreciation and depletion charge to net earnings. A downward revision in reserves could result in a writedown of oil and gas producing properties as part of the impairment assessment (see Asset Impairment discussion below).

Asset Retirement Obligations

The Company currently records the obligation for estimated asset retirement costs at fair value when incurred. Factors that can affect the fair values of the obligations include the expected costs to be incurred, the useful lives of the assets and discount rates applied. Cost estimates are influenced by factors such as the number and type of assets subject to asset retirement obligations, the extent of work required and changes in environmental legislation. A revision to the estimated costs to be incurred, useful lives of the assets or discount rates applied could result in an increase or decrease in the total obligation, which would change the amount of amortization and accretion expense recognized in net earnings over time.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows with the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion on page 59), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to

Management, Audit, Finance and Risk Committee, and Auditor Reports

Management's Responsibility for the Financial Statements and Report on Internal Control over Financial Reporting

The preparation and presentation of the Company's Consolidated Financial Statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and necessarily include estimates, which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for establishing and maintaining a system of internal controls over financial reporting to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements. Management conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's system of internal control over financial reporting was effective as at December 31, 2008.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect misstatements on a timely basis. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP, the Company's Independent Registered Chartered Accountants, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. Deloitte & Touche LLP also audited the Company's Consolidated Financial Statements for the year ended December 31, 2008.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board of Directors.

R. A. Brenneman

Ron A. Brenneman
President and Chief Executive Officer
February 23, 2009

E. F. H. Roberts

E. F. H. Roberts
Executive Vice-President and Chief Financial Officer
February 23, 2009

Audit, Finance and Risk Committee of the Board of Directors

The Audit, Finance and Risk Committee (the Committee), which is composed of not fewer than three (currently five) independent directors, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly Consolidated Financial Statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board of Directors regarding financial matters and oversees the process that management has in place to identify business risks. The Committee members are all independent pursuant to National Instrument 52-110 (NI 52-110), NYSE Corporate Governance Standards and the Sarbanes-Oxley Act of 2002 (SOX), and are financially literate, with one member who has been recognized as a "financial expert" in accordance with SOX requirements.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit, and reviews the results of the audit and the Reports of the Independent Registered Chartered Accountants. The external auditors report to the Committee. The Committee discusses the external auditors' independence from management and the Company with the external auditors and receives written confirmation of their independence. The Committee also recommends to the Board of Directors the external auditors to be appointed by the shareholders and approves in advance fees for the external auditors' services.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations. The contract auditor reports to the Committee.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.

Paul D. Melnuk
Chairman of the Audit, Finance and Risk Committee
February 23, 2009

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Petro-Canada:

We have audited the internal control over financial reporting of Petro-Canada and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Responsibility for the Financial Statements and Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated Financial Statements as at and for the year ended December 31, 2008 of the Company and our report dated February 23, 2009 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to changes in accounting principles.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 23, 2009

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Petro-Canada:

We have audited the accompanying Consolidated Balance Sheet of Petro-Canada and subsidiaries (the "Company") as at December 31, 2008 and 2007, and the related Consolidated Statements of Earnings, Comprehensive Income, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of Petro-Canada and subsidiaries as at December 31, 2008 and 2007 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 23, 2009

Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 3 to the Consolidated Financial Statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the board of directors and shareholders on the Consolidated Financial Statements of Petro-Canada, dated February 23, 2009, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 23, 2009

Consolidated Statement of Earnings

(stated in millions of Canadian dollars, except per share amounts)

For the years ended December 31,		2008		2007		2006
Revenue						
Operating	$	27,585	$	21,710	$	18,911
Investment and other income (expense) *(Notes 6 and 8)*		200		(460)		(242)
		27,785		21,250		18,669
Expenses						
Crude oil and product purchases		14,507		10,291		9,649
Operating, marketing and general *(Note 7)*		3,877		3,552		3,180
Exploration *(Note 17)*		587		490		339
Depreciation, depletion and amortization *(Notes 7, 9 and 17)*		2,155		2,091		1,365
Unrealized (gain) loss on translation of foreign currency denominated long-term debt		664		(246)		(1)
Interest		242		165		165
		22,032		16,343		14,697
Earnings from Continuing Operations Before Income Taxes		5,753		4,907		3,972
Provision for Income Taxes *(Note 10)*						
Current		2,629		1,797		2,073
Future *(Note 13)*		(10)		377		311
		2,619		2,174		2,384
Net Earnings from Continuing Operations		3,134		2,733		1,588
Net Earnings from Discontinued Operations *(Note 5)*		-		–		152
Net Earnings	$	3,134	$	2,733	$	1,740
Earnings per Share from Continuing Operations *(Note 11)*						
Basic	$	6.47	$	5.59	$	3.15
Diluted	$	6.43	$	5.53	$	3.11
Earnings per Share *(Note 11)*						
Basic	$	6.47	$	5.59	$	3.45
Diluted	$	6.43	$	5.53	$	3.41

Consolidated Statement of Comprehensive Income

(stated in millions of Canadian dollars)

For the years ended December 31,		2008		2007		2006
Net earnings	$	3,134	$	2,733	$	1,740
Other comprehensive income (loss), net of tax						
Change in foreign currency translation adjustment		214		(260)		363
Comprehensive income	$	3,348	$	2,473	$	2,103

See accompanying Notes to Consolidated Financial Statements

Consolidated Statement of Cash Flows

(stated in millions of Canadian dollars)

For the years ended December 31,	2008	2007	2006
Operating Activities			
Net earnings	$ 3,134	$ 2,733	$ 1,740
Less: Net earnings from discontinued operations	–	–	152
Net earnings from continuing operations	3,134	2,733	1,588
Items not affecting cash flow from continuing operating activities:			
Depreciation, depletion and amortization *(Notes 7, 9 and 17)*	2,155	2,091	1,365
Future income taxes *(Note 13)*	(10)	377	311
Accretion of asset retirement obligations *(Note 22)*	79	70	54
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	664	(246)	(1)
Gain on sale of assets *(Notes 6 and 8)*	(4)	(81)	(30)
Unrealized losses related to Buzzard derivative contracts *(Note 27)*	–	–	259
Other	91	9	18
Exploration expenses *(Notes 13 and 17)*	369	290	123
Settlement of Buzzard derivative contracts *(Note 27)*	–	(1,481)	–
(Increase) decrease in non-cash working capital related to continuing operating activities *(Note 12)*	44	(423)	(79)
Cash flow from continuing operating activities	6,522	3,339	3,608
Cash flow from discontinued operating activities *(Note 5)*	–	–	15
Cash flow from operating activities	6,522	3,339	3,623
Investing Activities			
Expenditures on property, plant and equipment and exploration *(Notes 13 and 17)*	(6,344)	(3,988)	(3,435)
Proceeds from sale of assets *(Notes 5 and 8)*	250	183	688
Increase in other assets	(29)	(121)	(50)
Decrease in non-cash working capital related to investing activities *(Note 12)*	739	279	59
Cash flow used in investing activities	(5,384)	(3,647)	(2,738)
Financing Activities			
Increase (decrease) in short-term notes payable *(Note 20)*	(109)	109	–
Proceeds from issue of long-term debt *(Note 20)*	1,482	995	–
Repayment of long-term debt *(Note 20)*	(998)	(7)	(7)
Proceeds from issue of common shares *(Note 23)*	21	37	44
Purchase of common shares *(Note 23)*	–	(839)	(1,011)
Dividends on common shares *(Note 26)*	(320)	(255)	(201)
Cash flow from (used in) financing activities	76	40	(1,175)
Increase (Decrease) in Cash and Cash Equivalents	$ 1,214	$ (268)	$ (290)
Cash and Cash Equivalents at Beginning of Year	$ 231	$ 499	$ 789
Cash and Cash Equivalents at End of Year *(Note 15)*	$ 1,445	$ 231	$ 499

See accompanying Notes to Consolidated Financial Statements

Consolidated Balance Sheet

(stated in millions of Canadian dollars)

As at December 31,		2008		2007
Assets				
Current Assets				
Cash and cash equivalents *(Note 15)*	$	1,445	$	231
Accounts receivable *(Note 14)*		2,844		1,973
Income taxes receivable		-		280
Inventories *(Notes 3 and 16)*		1,289		668
Future income taxes *(Notes 10 and 13)*		25		26
		5,603		3,178
Property, Plant and Equipment, Net *(Notes 8, 13 and 17)*		23,485		19,497
Goodwill *(Note 18)*		852		731
Other Assets *(Note 19)*		437		446
	$	30,377	$	23,852
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	$	3,186	$	3,512
Income taxes payable		1,018		-
Short-term notes payable *(Note 20)*		-		109
Current portion of long-term debt *(Note 20)*		3		2
		4,207		3,623
Long-Term Debt *(Note 20)*		4,746		3,339
Other Liabilities *(Notes 13 and 21)*		1,240		717
Asset Retirement Obligations *(Note 21)*		1,527		1,234
Future Income Taxes *(Notes 3, 10 and 13)*		3,182		3,069
Commitments and Contingent Liabilities *(Note 28)*				
Shareholders' Equity				
Common shares *(Note 23)*		1,388		1,365
Contributed surplus *(Note 23)*		22		24
Retained earnings		14,062		10,692
Accumulated other comprehensive income (loss)				
Foreign currency translation adjustment		3		(211)
		15,475		11,870
	$	30,377	$	23,852

Consolidated Statement of Retained Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,		2008		2007		2006
Retained Earnings at Beginning of Year	$	10,692	$	8,557	$	7,018
Cumulative effect of adopting new accounting standards *(Note 3)*		556		8		-
Net earnings		3,134		2,733		1,740
Dividends on common shares *(Note 26)*		(320)		(255)		(201)
Excess cost for normal course issuer bid *(Note 23)*		-		(351)		-
Retained Earnings at End of Year	$	14,062	$	10,692	$	8,557

See accompanying Notes to Consolidated Financial Statements

Approved on behalf of the Board of Directors

R.A. Brenneman

Ron A. Brenneman
Director

Brian F. MacNeill
Director

Notes to Consolidated Financial Statements

(stated in millions of Canadian dollars, unless otherwise stated)

Note 1 Summary of Significant Accounting Policies

a) Basis of Presentation

The Consolidated Financial Statements include the accounts of Petro-Canada and all subsidiary companies (the "Company") and are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Differences between Canadian and United States GAAP are explained in Note 30.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interests in such activities are reflected in the Consolidated Financial Statements.

The preparation of the Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, income taxes, employee future benefits, the estimates of oil and natural gas reserves and related depreciation, depletion and amortization, and the valuation of goodwill.

b) Revenue Recognition

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners. Inter-segment sales are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer; these amounts are eliminated on consolidation.

International operations conducted pursuant to Exploration and Production Sharing Agreements (EPSAs) are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the EPSAs, the Company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the Company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country. Cost Recovery Oil, Profit Oil and amounts in respect of all income taxes payable by the Company under the laws of the respective country are reported as sales revenue. All other government stakes, other than income taxes, are considered to be royalty interests.

c) Transportation Costs

Transportation costs incurred to transport crude oil, natural gas and refined petroleum products to customers, which are included in operating, marketing and general expenses, are recognized when the product is delivered and the service is provided.

d) Foreign Currency Translation

Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. With the exception of items pertaining to self-sustaining operations, all property, plant and equipment and related depreciation, depletion and amortization are translated at rates of exchange in effect when the assets were acquired. All other assets, liabilities, revenue and expense items are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

Note 1 Summary of Significant Accounting Policies *continued*

d) Foreign Currency Translation *continued*

The Company's International business segment and the U.S. Rockies upstream operations included in the North American Natural Gas business segment are operated on a self-sustaining basis. Assets and liabilities of these operations, including associated long-term debt, are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are presented as a separate component of other comprehensive income (loss) on the Consolidated Statement of Comprehensive Income.

e) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the temporary differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

f) Earnings Per Share

Basic earnings per share are calculated by dividing the net earnings available to common shareholders by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding stock options with a cash payment alternative (CPA), were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period. A liability and expense is recorded for stock options with a CPA. Accordingly, the potential issuance of common shares associated with these stock options is not included in the calculation of diluted earnings per share.

g) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in banks, less outstanding cheques, and short-term investments with a maturity of 90 days or less when purchased.

h) Sale of Accounts Receivable

The transfers of accounts receivable are accounted for as sales, other than the retained interest, when the Company has surrendered control over the transferred receivables and received proceeds. Gains or losses are recognized as other income or expenses and are dependent upon the purchase discount as well as the previous carrying amount of the receivables transferred, which is allocated between the receivables sold and the retained interest, based on their relative fair values at the date of the transfer. Fair value is determined based on the present value of future expected cash flows.

i) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and refined petroleum products is determined on a "first-in, first-out" (FIFO) basis (Note 3). Cost of other inventory is determined on an average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

j) Investments

Investments in companies over which the Company has significant influence are accounted for using the equity method.

Note 1 Summary of Significant Accounting Policies *continued*

k) Property, Plant and Equipment

Investments in exploration and development activities, including *in situ* oil sands activities, are accounted for using the successful efforts method. Under this method, the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells, which are assigned proved reserves, remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Acquisition, exploration and development of oil sands mining activities are capitalized when costs are recoverable and directly result in an identifiable future benefit.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period until the facilities are substantially complete. The amount of interest capitalized for the period is the product of the average accumulated capitalized costs, the Company's average corporate debt to equity ratio, and the weighted-average interest rate applicable to all borrowings outstanding during the period. Capitalized interest cannot exceed the actual interest incurred.

Producing properties and significant unproved properties, including oil sands properties (both mining and *in situ*) and other plant and equipment, are assessed annually, at minimum, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the amount by which the carrying value of the asset exceeds its fair value is recorded as an impairment in depreciation, depletion and amortization expense.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred, and improvements that increase capacity or extend the useful lives of assets are capitalized.

l) Depreciation, Depletion and Amortization

Depreciation and depletion of capitalized costs of oil and gas producing properties, including *in situ* oil sands properties, are calculated using the unit of production method. Development and exploration drilling and equipment costs of oil and gas producing properties, including wells, gathering facilities, and central processing facilities of *in situ* oil sands activities, are depleted over the remaining proved developed reserves. Proved property acquisition costs are depleted over the remaining proved reserves.

Depreciation and depletion of capitalized costs of oil sands mining properties are calculated using the unit of production method. Acquisition costs are depleted over proved and probable reserves. All other oil sands mining assets, including extraction and upgrading facilities, are depleted over proved reserves.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, as appropriate. Straight line depreciation is based on the estimated service lives of the related assets, which range from three to 25 years.

Costs associated with significant development projects are not depleted until commencement of commercial production.

Depreciation, depletion and amortization rates for all capitalized costs associated with all of the Company's activities are reviewed, at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

Note 1 Summary of Significant Accounting Policies *continued*

m) Asset Retirement Obligations

The fair values of estimated asset retirement obligations are recorded as liabilities when incurred and the associated cost is capitalized as part of the cost of the related asset. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The associated accretion is recorded in operating, marketing and general expense and the depreciation is included in depreciation, depletion and amortization expense. Changes in the estimated obligation resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and related asset. Actual expenditures incurred are charged against the accumulated obligation.

n) Goodwill

Acquisitions are accounted for using the purchase method. Under this method, identifiable assets and liabilities are recorded at fair value as of the date of acquisition. Goodwill, which is not amortized, is the excess of the purchase price over such fair value and is assigned to the appropriate reporting units.

The carrying value of goodwill is assessed for impairment annually at year end, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

o) Stock-Based Compensation

The Company maintains stock option, stock appreciation rights (SARs), performance share units (PSUs) and deferred share units (DSUs) plans as described in Note 24.

The Company accounts for stock options granted prior to 2003 based on the intrinsic value at the grant date, which does not result in a charge to earnings because the exercise price was equal to the market price at the grant date.

Stock options granted in 2003 are accounted for using the fair value method. Fair values are determined, at the grant date, using the Black-Scholes option-pricing model. The compensation expense associated with these options is charged to earnings over the vesting period with a corresponding increase in contributed surplus. When stock options are exercised, consideration paid and the associated contributed surplus are credited to common shares.

Stock options granted subsequent to 2003, all of which provide the holder the right to exercise the stock option or surrender the option for a cash payment, are accounted for based on the intrinsic value at each period end. A liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holder and the previously recognized liability associated with the stock options are recorded as common shares.

SARs, which entitle the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's shares on the date of surrender, are accounted for based on the intrinsic value at each period. A liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the exercise price of the SARs.

The compensation cost for a stock-based award that is attributable to an employee who is eligible to retire at the grant date is recognized on the grant date if the employee can retire from the Company at any point and the ability to exercise the award does not depend on continued service. The compensation expense associated with stock-based awards granted to employees who will become eligible to retire during the vesting period is recognized over the period from the grant date to the date the employee becomes eligible to retire.

Note 1 Summary of Significant Accounting Policies *continued*

o) Stock-Based Compensation *continued*

PSUs are accounted for on a mark-to-market basis over the term of the PSUs whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current total shareholder return relative to a peer group of North American industry competitors.

DSUs are accounted for on a mark-to-market basis whereby a liability and expense are recorded each period based on the number of DSUs outstanding and the current market price of the Company's shares.

p) Employee Future Benefits

The Company's employee future benefit programs consist of both defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in Note 25.

The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method, pro-rated based on service and using management's best estimate of expected plan investment performance, discount rates, salary escalation, retirement ages of employees and expected health and dental care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the end of the year on high quality corporate debt instruments. The excess of the cumulative unamortized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees.

Company contributions to the defined contribution plan are expensed as incurred.

q) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. The Company has classified each financial instrument into one of the following categories: held-for-trading financial assets and liabilities, loans and receivables, held-to-maturity financial assets, and other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Held-for-trading financial assets and liabilities are subsequently measured at fair value with changes in those fair values recognized in net earnings.

Loans and receivables, held-to-maturity financial assets and other financial liabilities are subsequently measured at amortized cost using the effective interest method.

The Company classifies cash and cash equivalents as held-for-trading financial assets, accounts receivable as loans and receivables, and accounts payable and accrued liabilities, short-term notes payable and long-term debt as other financial liabilities.

The Company combines transaction costs and premiums or discounts directly attributable to the issuance of long-term debt with the fair value of the debt and amortizes these amounts to earnings using the effective interest method.

The Company classifies financial instruments that are derivative contracts as held-for-trading financial assets and liabilities unless designated as effective hedges.

r) Hedging and Derivatives

The Company may use derivative contracts to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates and commodity prices. These derivative contracts are not used for speculative purposes. The Company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

Note 1 Summary of Significant Accounting Policies *continued*

r) Hedging and Derivatives *continued*

Derivative contracts that are not designated as hedges for accounting purposes are recorded on the Consolidated Balance Sheet at fair value with any resulting gain or loss recognized in investment and other income (expense) on the Consolidated Statement of Earnings.

The Company formally documents all derivative contracts designated as hedges, the risk management objective and the strategy for undertaking the hedge.

For designated cash flow hedges, the portion of the gain (loss) on the hedging item that is deemed to be effective is recognized in other comprehensive income (loss), net of tax, on the Consolidated Statement of Comprehensive Income, and is then reclassified to the Consolidated Statement of Earnings in the same period or periods during which the hedged item affects net earnings. The portion of the gain (loss) that is deemed to be ineffective is recognized immediately in net earnings in the period in which it occurs.

For designated fair value hedges, both the hedging item and the underlying hedged item are measured at fair value. Changes in the fair value of both items are recognized immediately in net earnings in the period in which they occur.

The Company assesses, both at inception and over the term of the hedging relationship, whether the derivative contracts used in the hedging transactions are highly effective in offsetting changes in the fair value or cash flows of hedged items. If a derivative contract ceases to be effective or is terminated, hedge accounting is discontinued. Any gains (losses) relating to terminated cash flow hedges included in other comprehensive income (loss) are typically reclassified to net earnings in the period in which the cash flow hedge is terminated.

Note 2 International Financial Reporting Standards

During 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) in place of Canadian GAAP for interim and annual reporting purposes. The required changeover date is for fiscal years beginning on or after January 1, 2011. At this time, the impact on the Company's Consolidated Financial Statements is not reasonably determinable.

Note 3 Changes in Accounting Policies

On January 1, 2008, 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.*

As a result of adopting CICA Section 1535, *Capital Disclosures*, the Company now discloses details about its capital management strategy (Note 26).

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 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 has not restated prior period amounts. As such, the following balance sheet categories were impacted on January 1, 2008:

Note 3 Changes in Accounting Policies *continued*

		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 27).

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

Note 4 Segmented Information from Continuing Operations

The Company is an integrated oil and gas company with activities spanning both the upstream and downstream sectors of the industry. The Company conducts its business through five major operating business segments along with Shared Services. Upstream activities are conducted through four business segments, which include North American Natural Gas, Oil Sands, East Coast Canada and International. Downstream operations comprise the fifth business segment.

Upstream operations include the exploration, development, production, transportation and marketing of crude oil, natural gas and natural gas liquids and oil sands. The North American Natural Gas segment includes activity in Western Canada, the U.S. Rockies, the Mackenzie Delta/Corridor, and Alaska. The Oil Sands segment includes interests in the Syncrude oil sands mining operation, the MacKay River *in situ* oil sands operation, and the Fort Hills oil sands project. The East Coast Canada segment comprises activity offshore Newfoundland and Labrador, and includes interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields. The International segment includes activity in the United Kingdom (U.K.), the Netherlands, Trinidad and Tobago, Libya and Syria.

The Downstream business segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

Financial information by business segment is presented in the following table as though each segment was a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, gains or losses on foreign currency translation, including unrealized gains or losses on foreign currency denominated long-term debt, and general corporate revenue and expenses. Shared Services assets are principally cash and cash equivalents and other general corporate assets.

Eliminations includes sales between segments and unrealized inter-segment profits and losses on inventories. These figures were previously included in Shared Services.

Note 4 Segmented Information from Continuing Operations *continued*

	Upstream					
	North American Natural Gas			Oil Sands		
	2008	2007	2006	**2008**	2007	2006
Revenue[1]						
Sales to customers	**$ 1,931**	$ 1,347	$ 1,504	**$ 1,915**	$ 611	$ 592
Investment and other income (expense)[2]	**(121)**	66	6	**10**	(2)	–
Inter-segment sales	**421**	324	349	**1,510**	1,065	822
Segmented revenue	**2,231**	1,737	1,859	**3,435**	1,674	1,414
Expenses						
Crude oil and product purchases[3]	**461**	240	256	**1,796**	524	425
Inter-segment transactions	**7**	10	5	**40**	13	31
Operating, marketing and general	**545**	491	462	**913**	595	508
Exploration	**147**	192	150	**13**	28	21
Depreciation, depletion and amortization	**575**	584	402	**202**	149	128
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	**–**	–	–	**–**	–	–
Interest	**–**	–	–	**–**	–	–
	1,735	1,517	1,275	**2,964**	1,309	1,113
Earnings (loss) from continuing operations before income taxes	**496**	220	584	**471**	365	301
Provision for income taxes						
Current	**118**	183	351	**97**	(13)	(53)
Future	**34**	(154)	(172)	**40**	62	109
	152	29	179	**137**	49	56
Net earnings (loss) from continuing operations	**$ 344**	$ 191	$ 405	**$ 334**	$ 316	$ 245
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	**$ 1,023**	$ 866	$ 788	**$ 1,063**	$ 779	$ 377
Other assets	**–**	7	5	**29**	69	1
	$ 1,023	$ 873	$ 793	**$ 1,092**	$ 848	$ 378
Cash flow from (used in) continuing operating activities	**$ 1,055**	$ 725	$ 651	**$ 622**	$ 512	$ 499
Total assets from continuing operations	**$ 4,605**	$ 4,119	$ 4,151	**$ 4,566**	$ 3,659	$ 2,885

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 Investment and other income (expense) for the International segment includes $nil (2007 – $535 million; 2006 – $259 million) of losses related to the Buzzard derivative contracts (Note 27).

3 Downstream crude oil and product purchases account for substantially all of the Downstream inventories recognized as an expense for the periods presented.

Note 4 Segmented Information from Continuing Operations *continued*

	Upstream					
	International & Offshore					
	East Coast Canada			International		
	2008	2007	2006	2008	2007	2006
Revenue[1]						
Sales to customers	$ 2,605	$ 2,708	$ 2,004	$ 4,892	$ 3,697	$ 2,464
Investment and other income (expense)[2]	20	(18)	-	164	(549)	(283)
Inter-segment sales	789	477	298	12	-	-
Segmented revenue	3,414	3,167	2,302	5,068	3,148	2,181
Expenses						
Crude oil and product purchases[3]	770	736	452	-	-	-
Inter-segment transactions	8	8	9	-	-	-
Operating, marketing and general	254	228	245	460	526	350
Exploration	1	13	12	426	257	156
Depreciation, depletion and amortization	389	410	237	663	640	323
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	-	-	-	-	-	-
Interest	-	-	-	-	-	-
	1,422	1,395	955	1,549	1,423	829
Earnings (loss) from continuing operations before income taxes	1,992	1,772	1,347	3,519	1,725	1,352
Provision for income taxes						
Current	647	653	434	2,163	848	1,248
Future	(23)	(110)	(21)	(328)	503	310
	624	543	413	1,835	1,351	1,558
Net earnings (loss) from continuing operations	$ 1,368	$ 1,229	$ 934	$ 1,684	$ 374	$ (206)
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	$ 276	$ 159	$ 256	$ 2,115	$ 762	$ 760
Other assets	-	2	-	-	-	-
	$ 276	$ 161	$ 256	$ 2,115	$ 762	$ 760
Cash flow from (used in) continuing operating activities	$ 1,850	$ 1,491	$ 1,129	$ 2,380	$ 220	$ 840
Total assets from continuing operations	$ 2,149	$ 2,345	$ 2,465	$ 8,277	$ 5,180	$ 6,031

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 Investment and other income (expense) for the International segment includes $nil (2007 – $535 million; 2006 – $259 million) of losses related to the Buzzard derivative contracts (Note 27).

3 Downstream crude oil and product purchases account for substantially all of the Downstream inventories recognized as an expense for the periods presented.

Note 4 Segmented Information from Continuing Operations *continued*

	Downstream			Shared Services		
	2008	2007	2006	2008	2007	2006
Revenue[1]						
Sales to customers	$ 16,242	$ 13,347	$ 12,347	$ –	$ –	$ –
Investment and other income (expense)[2]	38	(12)	19	89	55	16
Inter-segment sales	15	18	15	–	–	–
Segmented revenue	16,295	13,353	12,381	89	55	16
Expenses						
Crude oil and product purchases[3]	11,580	8,787	8,517	–	–	–
Inter-segment transactions	2,692	1,853	1,439	–	–	–
Operating, marketing and general	1,761	1,525	1,495	(56)	187	120
Exploration	–	–	–	–	–	–
Depreciation, depletion and amortization	325	299	262	1	9	13
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	–	–	–	664	(246)	(1)
Interest	–	–	–	242	165	165
	16,358	12,464	11,713	851	115	297
Earnings (loss) from continuing operations before income taxes	(63)	889	668	(762)	(60)	(281)
Provision for income taxes						
Current	(294)	232	141	(102)	(106)	(48)
Future	231	28	54	41	49	31
	(63)	260	195	(61)	(57)	(17)
Net earnings (loss) from continuing operations	$ –	$ 629	$ 473	$ (701)	$ (3)	$ (264)
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	$ 1,834	$ 1,396	$ 1,229	$ 33	$ 26	$ 24
Other assets	–	30	22	–	13	22
	$ 1,834	$ 1,426	$ 1,251	$ 33	$ 39	$ 46
Cash flow from (used in) continuing operating activities	$ 464	$ 994	$ 835	$ 151	$ (603)	$ (346)
Total assets from continuing operations	$ 10,057	$ 7,989	$ 6,649	$ 734	$ 563	$ 464

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 Investment and other income (expense) for the International segment includes $nil (2007 – $535 million; 2006 – $259 million) of losses related to the Buzzard derivative contracts (Note 27).

3 Downstream crude oil and product purchases account for substantially all of the Downstream inventories recognized as an expense for the periods presented.

Note 4 Segmented Information from Continuing Operations *continued*

	Eliminations			Consolidated		
	2008	2007	2006	2008	2007	2006
Revenue[1]						
Sales to customers	$ –	$ –	$ –	$ 27,585	$ 21,710	$ 18,911
Investment and other income (expense)[2]	–	–	–	200	(460)	(242)
Inter-segment sales	(2,747)	(1,884)	(1,484)	–	–	–
Segmented revenue	(2,747)	(1,884)	(1,484)	27,785	21,250	18,669
Expenses						
Crude oil and product purchases[3]	(100)	4	(1)	14,507	10,291	9,649
Inter-segment transactions	(2,747)	(1,884)	(1,484)	–	–	–
Operating, marketing and general	–	–	–	3,877	3,552	3,180
Exploration	–	–	–	587	490	339
Depreciation, depletion and amortization	–	–	–	2,155	2,091	1,365
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	–	–	–	664	(246)	(1)
Interest	–	–	–	242	165	165
	(2,847)	(1,880)	(1,485)	22,032	16,343	14,697
Earnings (loss) from continuing operations before income taxes	100	(4)	1	5,753	4,907	3,972
Provision for income taxes						
Current	–	–	–	2,629	1,797	2,073
Future	(5)	(1)	–	(10)	377	311
	(5)	(1)	–	2,619	2,174	2,384
Net earnings (loss) from continuing operations	$ 105	$ (3)	$ 1	$ 3,134	$ 2,733	$ 1,588
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	$ –	$ –	$ –	$ 6,344	$ 3,988	$ 3,434
Other assets	–	–	–	29	121	50
	$ –	$ –	$ –	$ 6,373	$ 4,109	$ 3,484
Cash flow from (used in) continuing operating activities	$ –	$ –	$ –	$ 6,522	$ 3,339	$ 3,608
Total assets from continuing operations	$ (11)	$ (3)	$ 1	$ 30,377	$ 23,852	$ 22,646

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 Investment and other income (expense) for the International segment includes $nil (2007 – $535 million; 2006 – $259 million) of losses related to the Buzzard derivative contracts (Note 27).

3 Downstream crude oil and product purchases account for substantially all of the Downstream inventories recognized as an expense for the periods presented.

Note 4 Segmented Information from Continuing Operations *continued*

Geographic Information from Continuing Operations

	2008		2007		2006	
	Revenues	**Total Assets**	Revenues	Total Assets	Revenues	Total Assets
Canada	**$ 22,317**	**$ 19,942**	$ 17,897	$ 17,020	$ 16,295	$ 14,736
Foreign[1]	**5,468**	**10,435**	3,353	6,832	2,374	7,910
	$ 27,785	**$ 30,377**	$ 21,250	$ 23,852	$ 18,669	$ 22,646

1 Foreign total assets include $2,767 million relating to assets in the U.K. (2007 – $3,185 million; 2006 – $3,692 million).

Note 5 Discontinued Operations

In January 2006, the Company completed the sale of its producing assets in Syria for net proceeds of $640 million, resulting in a gain on sale of $134 million.

The accounting for discontinued operations results in a reduction of the Consolidated Statement of Earnings balances as follows:

	2008	2007	2006
Revenue			
Operating	**$ –**	$ –	$ 34
Investment and other income (expense)[1]	**–**	–	134
	–	–	168
Expenses			
Operating, marketing and general	**–**	–	6
	–	–	6
Earnings from discontinued operations before income taxes	**–**	–	162
Provision for income taxes	**–**	–	10
Net earnings from discontinued operations	**$ –**	$ –	$ 152

1 2006 investment and other income (expense) includes the gain on sale of $134 million.

Note 6 Investment and Other Income (Expense)

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

	2008	2007	2006
Foreign exchange gains (losses)	**$ 128**	$ (10)	$ (41)
Gain on sale of assets *(Note 8)*	**4**	81	30
Losses related to Buzzard derivative contracts *(Note 27)*	**–**	(535)	(259)
Gain (loss) on Downstream derivative contracts	**24**	(26)	2
Other	**44**	30	26
Total investment and other income (expense)	**$ 200**	$ (460)	$ (242)

Note 7 Fort Hills Project

Project Status

In November 2008, the Company and its partners, UTS Energy Corporation (UTS) and Teck Cominco Limited (Teck), announced that the preliminary results from the Fort Hills project front-end engineering and design (FEED) work suggest that estimated costs have risen considerably and, therefore, a final investment decision (FID) on both the mining and upgrading portions of the project will be deferred until a cost estimate consistent with the current market environment can be established. As a result, the Company has recognized an $87 million ($64 million after-tax) impairment charge on certain property, plant and equipment and expenses of $129 million ($92 million after-tax) to reflect the termination or suspension of some agreements for the receipt of goods and services.

The impairment charge is included in depreciation, depletion and amortization expense and the goods and services agreements termination expenses are included in operating, marketing and general expense, both on the Consolidated Statement of Earnings.

Increase in Working Interest

In November 2007, the Company finalized an agreement to acquire an additional 5% working interest in the Fort Hills project, bringing the Company's total working interest to 60%. To pay for this incremental investment, the Company is funding $375 million of expenditures in excess of its working interest. The acquisition cost was discounted using the Company's estimated cost of debt at the time of acquisition and an estimated payout pattern for the funding. This payout pattern was revised in December 2008 due to the deferral of the FID. At December 31, 2008, $349 million of the discounted acquisition cost was outstanding, with $43 million (December 31, 2007 – $18 million) recorded in accounts payable and accrued liabilities and $306 million (December 31, 2007 – $329 million) recorded in other liabilities.

Note 8 Sale of Assets

In August 2008, the Company completed the sale of its pre-development assets in Denmark, which are a part of the Company's International business segment, for net proceeds of $140 million, resulting in a gain on sale of $107 million ($82 million after-tax) (Note 18).

In June 2008, the Company completed the sale of its Minehead assets in Western Canada, which are a 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 gains and losses on the sales of these assets are included in investment and other income (expense) on the Consolidated Statement of Earnings.

Note 9 Asset Write-Downs

In December 2007, the Company recognized a $150 million ($97 million after-tax) impairment expense due to a write-down of its coal bed methane assets in the U.S. Rockies' Powder River Basin. The assets were written down to management's best estimate of fair value based on a discounted future cash flow valuation. These assets form part of the Company's North American Natural Gas business segment.

The impairment expense is included in depreciation, depletion and amortization expense on the Consolidated Statement of Earnings.

Note 10 Income Taxes

The computation of the provision for income taxes is as follows:

		2008		2007		2006
Earnings from continuing operations before income taxes	$	**5,753**	$	4,907	$	3,972
Add (deduct):						
Non-deductible royalties and other payments to provincial governments, net		**–**		–		61
Resource allowance		**–**		–		(158)
Non-taxable foreign exchange		**448**		(126)		(1)
Other		**(33)**		(26)		(24)
Earnings from continuing operations as adjusted before income taxes	$	**6,168**	$	4,755	$	3,850
Canadian federal income tax rate		**38.0%**		38.0%		38.0%
Income tax on earnings from continuing operations as adjusted at Canadian federal income tax rate	$	**2,344**	$	1,807	$	1,463
Provincial income taxes		**295**		372		295
Federal – abatement and other credits		**(452)**		(446)		(262)
Current income tax increase due to Canadian federal and provincial reassessments and proposed reassessments		**38**		–		70
Future income tax decrease due to Canadian rate changes		**(26)**		(155)		(63)
Future income tax increase (decrease) due to foreign rate changes		**3**		(36)		242
Future income tax decrease due to ratification of Libya EPSAs		**(230)**		–		–
Higher foreign income tax rates		**691**		622		627
Income tax credits and other		**(44)**		10		12
Provision for income taxes	$	**2,619**	$	2,174	$	2,384
Effective income tax rate on earnings from continuing operations before income taxes		**45.5%**		44.3%		60.0%

The provision for income taxes is comprised of:

		2008		2007		2006
Current						
Canadian	$	**428**	$	257	$	801
Foreign		**2,201**		1,541		1,272
Future						
Canadian		**265**		443		62
Foreign *(Note 13)*		**(275)**		(67)		249
Total provision for income taxes	$	**2,619**	$	2,174	$	2,384

The provisions for current and future income taxes include tax recoveries (expenses), which are largely due to future income tax recoveries on ratification of the Libya EPSAs and changes to income tax rates. These amounts have been allocated to the business segments as follows:

		2008		2007		2006
North American Natural Gas	$	**–**	$	8	$	6
Oil Sands		**2**		62		44
International & Offshore						
East Coast Canada		**2**		52		37
International[1] *(Note 13)*		**227**		30		(306)
Downstream		**2**		34		41
Shared Services[2]		**(18)**		5		(71)
	$	**215**	$	191	$	(249)

1 Included in the International's $227 million income tax recovery for 2008 is a $230 million future income tax recovery recognized on ratification of the Libya EPSAs. Included in International's $306 million income tax expense for 2006 is a $242 million increase in the future income tax provision due to an increase in the U.K. supplemental corporate income tax rate and the resulting impact of qualifying capital expenditures being deducted at the increased rate.

2 Included in the Shared Services' $71 million income tax expense for 2006 is a $70 million increase in the provision for current income taxes due to the Quebec government enacting retroactive tax legislation.

Note 10 Income Taxes *continued*

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

		2008		2007
Future income tax liabilities				
Property, plant and equipment	$	**3,346**	$	3,626
Partnership income[1]		**473**		362
Other assets		**71**		78
Future income tax assets				
Asset retirement obligations and other liabilities		**(577)**		(495)
Inventories		**-**		(256)
Other		**(156)**		(272)
Net future income tax liability		**3,157**		3,043
Less: Current future income tax asset		**(25)**		(26)
Future income tax liability	$	**3,182**	$	3,069

1 Taxable income for certain Canadian upstream activities is generated by a partnership and the related taxes will be included in current income taxes in the next year.

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

Complex income tax issues, which involve interpretations of continually changing regulations, are encountered in computing the provision for income taxes. Management believes that adequate provisions have been made for all such outstanding issues and that the resolution of these issues would not materially affect the financial position or results of operations of the Company.

Note 11 Earnings per Share

The weighted-average number of common shares outstanding used in the calculations of basic and diluted earnings per share from continuing operations and earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

(millions)	2008	2007	2006
Weighted-average number of common shares outstanding – basic	**484.1**	489.0	503.9
Effect of dilutive stock options	**3.6**	5.0	6.0
Weighted-average number of common shares outstanding – diluted	**487.7**	494.0	509.9

There were no stock options, not including stock options with a CPA (Note 1 (f)), excluded from the diluted earnings per share from continuing operations and earnings per share calculations. Stock options are excluded when the exercise price exceeds the average share price in a respective period.

Note 12 Cash Flow Information

Changes in Non-Cash Working Capital

Non-cash working capital is comprised of current assets and current liabilities, other than cash and cash equivalents and the current portion of long-term debt.

The (increase) decrease in non-cash working capital is comprised of:

	2008	2007	2006
Operating activities from continuing operations			
Accounts receivable	**$ (871)**	$ (373)	$ 17
Inventories	**(621)**	(36)	(36)
Accounts payable and accrued liabilities	**(326)**	77	365
Income taxes payable	**1,298**	(302)	(60)
Current portion of long-term liabilities and other	**564**	211	(365)
	$ 44	$ (423)	$ (79)
Investing activities			
Accounts payable and accrued liabilities	**$ 762**	$ 120	$ 138
Other liabilities	**(23)**	159	(79)
	$ 739	$ 279	$ 59

Cash Payments

Cash payments from continuing operations for interest and income taxes were as follows:

	2008	2007	2006
Interest	**$ 274**	$ 186	$ 194
Income taxes	**$ 1,475**	$ 2,074	$ 2,149

Note 13 Libya Exploration and Production Sharing Agreements

On June 19, 2008, the Company signed six new 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. Earnings on properties covered by the old agreements were adjusted based on the financial terms of the new EPSAs for the period from January 1, 2008 until ratification. The new EPSAs have an expected duration of 30 years and enable the Company to implement jointly with the NOC the redevelopment of major fields and conduct a 100% operated exploration program in the Libya Sirte Basin.

As part of the ratification, the Company agreed to 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 was discounted to $954 million based on this payout schedule using the Company's estimated cost of debt at the time of acquisition. At December 31, 2008, $554 million of the discounted signature bonus cost was outstanding, with $30 million recorded in accounts payable and accrued liabilities and $524 million recorded in other liabilities.

Net earnings for the year ended December 31, 2008 includes a $230 million future income tax recovery, which the Company recognized on ratification of the new EPSAs on June 19, 2008.

Note 14 Securitization Program

On June 24, 2004, the Company entered into a securitization program, expiring on June 24, 2009, to sell an undivided interest of eligible accounts receivable up to $500 million to a third party on a revolving and fully serviced basis. The service liability has been estimated to be insignificant.

During the year ended December 31, 2008, the Company suspended all sales of receivables to the program and remitted all funds for receivables previously sold. As at December 31, 2008, there were no outstanding receivables sold under the program. As at December 31, 2007, $480 million of outstanding accounts receivable had been sold under the program for net proceeds of $479 million.

Note 15 Cash and Cash Equivalents

	2008	2007
Cash	$ 204	$ 47
Short-term investments	1,241	184
	$ 1,445	$ 231

Note 16 Inventories

	2008	2007
Crude oil and refined petroleum products *(Note 3)*	$ 1,111	$ 484
Materials and supplies	178	184
	$ 1,289	$ 668

Note 17 Property, Plant and Equipment

	2008			2007			2008	2007
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Expenditures on Property, Plant and Equipment[1]	
North American Natural Gas	$ 8,210	$ 4,141	$ 4,069	$ 7,310	$ 3,536	$ 3,774	$ 925	$ 736
Oil Sands	5,317	1,124	4,193	4,359	1,011	3,348	1,058	759
International & Offshore								
East Coast Canada	4,308	2,389	1,919	4,059	2,003	2,056	276	155
International	7,568	2,045	5,523	5,689	1,605	4,084	1,849	626
Downstream	10,971	3,270	7,701	9,174	3,000	6,174	1,834	1,396
Shared Services	556	476	80	542	481	61	33	26
	$ 36,930	$ 13,445	$ 23,485	$ 31,133	$ 11,636	$ 19,497	$ 5,975	$ 3,698

1 Exploration expenses, excluding general and administrative and geological and geophysical expenses, of $369 million (2007 – $290 million; 2006 – $123 million) are reported in expenditures on property, plant and equipment and exploration under investing activities on the Consolidated Statement of Cash Flows.

Property, plant and equipment net cost includes asset retirement costs of $787 million (December 31, 2007 – $591 million).

Interest capitalized during 2008 amounted to $37 million (2007 – $30 million; 2006 – $51 million).

Note 17 Property, Plant and Equipment *continued*

Costs of work in progress and assets under construction, which are not currently being depreciated or depleted, were as follows:

	2008	2007
North American Natural Gas	**$ 51**	$ 21
Oil Sands	**1,538**	1,039
International & Offshore		
East Coast Canada	**225**	120
International	**829**	323
Downstream	**751**	2,151
	$ 3,394	$ 3,654

As at December 31, 2008, capital leases at a net cost of $52 million (December 31, 2007 – $56 million) and $18 million (December 31, 2007 – $21 million) are included in the assets of East Coast Canada and Oil Sands, respectively (Note 20).

Note 18 Goodwill

The following table summarizes the changes in goodwill:

	2008			2007		
	North American Natural Gas	**International**	**Total**	North American Natural Gas	International	Total
Goodwill at beginning of year	**$ 144**	**$ 587**	**$ 731**	$ 169	$ 632	$ 801
Foreign exchange	**34**	**102**	**136**	(25)	(45)	(70)
Other[1]	**–**	**(15)**	**(15)**	–	–	–
Goodwill at end of year	**$ 178**	**$ 674**	**$ 852**	$ 144	$ 587	$ 731

1 Other represents the carrying amount of goodwill related to the pre-development assets in Denmark sold during 2008 (Note 8).

Note 19 Other Assets

	2008	2007
Investments	**$ 88**	**$** 81
Accrued pension asset *(Note 25)*	**142**	168
Other long-term assets	**207**	197
	$ 437	**$** 446

Note 20 Long-Term Debt

	Maturity	2008	2007
Debentures and notes			
6.80% unsecured senior notes ($900 million US)	2038	$ 1,090	$ –
5.95% unsecured senior notes ($600 million US)	2035	719	577
5.35% unsecured senior notes ($300 million US)[1]	2033	320	248
7.00% unsecured debentures ($250 million US)	2028	296	237
7.875% unsecured debentures ($275 million US)	2026	332	267
9.25% unsecured debentures ($300 million US)	2021	365	294
6.05% unsecured senior notes ($600 million US)	2018	729	–
5.00% unsecured senior notes ($400 million US)[2]	2014	485	391
4.00% unsecured senior notes ($300 million US)[1]	2013	351	275
Syndicated credit facilities	2013	–	995
Capital leases *(Note 17)*[3]	2009-2022	62	57
		4,749	3,341
Current portion		(3)	(2)
		$ 4,746	$ 3,339

1 In anticipation of issuing these senior notes, the Company entered into interest rate derivatives, which resulted in effective interest rates of 6.073% for the 5.35% notes due in 2033 and 4.838% for the 4.00% notes due in 2013. These derivatives were settled in 2003.

2 These senior notes were issued by PC Financial Partnership, a wholly-owned finance subsidiary of Petro-Canada. Petro-Canada has fully and unconditionally guaranteed these senior notes.

3 The Company is party to one transportation and one time-charter agreement that are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time-charter agreements are $62 million, including the following amounts in the next five years: 2009 – $3 million; 2010 – $3 million; 2011 – $4 million; 2012 – $4 million; and 2013 – $5 million.

Interest on long-term debt and short-term notes payable, net of capitalized interest, was $234 million in 2008 (2007 – $151 million; 2006 – $152 million). Interest is paid semi-annually. All debentures and senior notes are repayable in full upon maturity.

Except as discussed in footnote 1 above, the fixed interest rate on all debentures and senior notes approximates the effective interest rate.

During the year, 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 and the United States. 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 December 31, 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 $777 million (December 31, 2007 – $1,500 million). During 2008, the Company had drawings on its syndicated credit facilities and its demand credit facilities in the form of Canadian and U.S. dollar Bankers' Acceptances. However, as of December 31, 2008, the Company had repaid all amounts previously drawn on its syndicated and demand credit facilities. The weighted-average interest rate for Bankers' Acceptances outstanding over the course of 2008 was 4.7% (2007 – 5.1%) for the syndicated credit facilities and 4.4% (2007 – 5.0%) for the demand credit facilities. At December 31, 2008, a total of $348 million of the credit facilities was used for letters of credit and overdraft coverage.

Subsequent to December 31, 2008, the Company put in place a bilateral committed credit facility in the amount of $244 million.

Note 21 Other Liabilities

		2008		2007
Fort Hills purchase obligation *(Note 7)*	$	**306**	$	329
Libya EPSAs signature bonus *(Note 13)*		**524**		–
Post-retirement benefits *(Note 25)*		**206**		193
Other long-term liabilities		**204**		195
	$	**1,240**	$	717

Note 22 Asset Retirement Obligations

Asset retirement obligations are recorded for obligations where the Company will be required to retire tangible long-lived assets such as well sites, offshore production platforms, natural gas processing plants and marketing sites.

The following table summarizes the changes in the asset retirement obligations:

		2008		2007
Asset retirement obligations at beginning of year	$	**1,283**	$	1,237
Obligations incurred		**219**		74
Changes in estimates		**67**		5
Obligations settled		**(67)**		(56)
Accretion expense		**79**		70
Foreign exchange		**(7)**		(47)
Asset retirement obligations at end of year		**1,574**		1,283
Less: Current portion		**(47)**		(49)
	$	**1,527**	$	1,234

In determining the fair value of the asset retirement obligations, the estimated cash flows of new obligations incurred during the year have been discounted at 7.5% (2007 – 6.5%). The total undiscounted amount of the estimated cash flows required to settle the obligations is $5,389 million (2007 – $4,136 million). The obligations will be settled on an ongoing basis over the useful lives of the operating assets, which extend up to 50 years in the future. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

Note 23 Shareholders' Equity

Authorized

The authorized share capital is comprised of an unlimited number of:

a) Preferred shares issuable in series designated as Senior Preferred Shares

b) Preferred shares issuable in series designated as Junior Preferred Shares

c) Common shares without par value

Note 23 Shareholders' Equity *continued*

Issued and Outstanding

Changes in common shares and contributed surplus were as follows:

	2008			2007		
	Shares	**Amount**	**Contributed Surplus**	Shares	Amount	Contributed Surplus
Balance at beginning of year	**483,459,119**	**$ 1,365**	**$ 24**	497,538,385	$ 1,366	$ 469
Issued under employee stock-option and share purchase plans	**1,138,348**	**23**	**(2)**	1,918,734	43	(1)
Repurchased under normal course issuer bid	**–**	**–**	**–**	(15,998,000)	(44)	(444)
Balance at end of year	**484,597,467**	**$ 1,388**	**$ 22**	483,459,119	$ 1,365	$ 24

The Company has 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 2008, the Company did not repurchase any common shares. During 2007, the Company repurchased 15,998,000 common shares at an average price of $52.42 per common share for a total cost of $839 million, with the excess of the purchase price over the carrying amount of the shares repurchased recorded as a $444 million reduction of contributed surplus and a $351 million reduction of retained earnings.

Note 24 Stock-Based Compensation

Stock Options

The Company maintains a stock option plan whereby options can be granted to officers and certain employees for up to 57 million common shares. Stock options have a term of 10 years if granted prior to 2004 and seven years if granted subsequent to 2003. All stock options vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

In 2004, the Company amended the option plan to provide the holder of stock options granted subsequent to 2003 the alternative to exercise these options as a CPA. Where the CPA is chosen, vested options can be surrendered for cancellation in return for a direct cash payment from the Company based on the excess of the then current market price over the option exercise price.

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

	2008	
	Number	**Weighted-Average Exercise Price** *(dollars)*
Balance at beginning of year	**21,035,064**	**$ 34**
Granted	**3,486,200**	**47**
Exercised for common shares	**(1,138,348)**	**17**
Surrendered for cash payment	**(897,604)**	**35**
Forfeited	**(347,410)**	**47**
Expired	**(4,000)**	**13**
Balance at end of year	**22,133,902**	**$ 37**

Note 24 Stock-Based Compensation *continued*

Stock Options *continued*

	2007		2006	
	Number	Weighted-Average Exercise Price *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
Balance at beginning of year	20,714,733	$ 31	18,361,617	$ 24
Granted	3,347,800	44	4,911,600	52
Exercised for common shares	(1,918,734)	19	(2,177,881)	20
Surrendered for cash payment	(800,685)	34	(119,710)	31
Forfeited	(307,550)	44	(260,643)	41
Expired	(500)	52	(250)	18
Balance at end of year	21,035,064	$ 34	20,714,733	$ 31

The following stock options were outstanding as at December 31, 2008:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices *(dollars)*	Number	Weighted-Average Life *(years)*	Weighted-Average Exercise Price *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
$ 8 to 13	680,888	0.8	$ 10	680,888	$ 10
14 to 19	2,742,356	2.6	18	2,742,356	18
20 to 25	2,723,190	3.8	25	2,723,190	25
26 to 31	2,028,459	2.1	29	2,028,459	29
32 to 37	2,987,009	3.1	34	2,151,909	34
38 to 43	3,278,300	5.0	44	855,975	44
44 to 49	3,477,850	6.1	47	48,350	48
50 to 57	4,215,850	4.1	52	2,136,200	52
$ 8 to 57	22,133,902	3.9	$ 37	13,367,327	$ 30

During 2008, the Company recorded compensation (recovery) expense of $(125) million (2007 – $69 million; 2006 – $31 million) relating to options with a CPA and compensation expense of $nil (2007 – $1 million; 2006 – $10 million) relating to the 2003 stock options, which had been fully expensed by December 31, 2007.

Stock Appreciation Rights (SARs)

Commencing 2007, the Company approved the issuance of SARs to certain employees, which entitle the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender. The vesting period and other terms are similar to the terms of the Company's existing stock option plan. At the time of grant, the exercise price approximated the market price. The following SARs have been granted:

	2008		2007	
	Number	**Weighted-Average Exercise Price** *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
Balance at beginning of year	**3,659,450**	**$ 44**	–	$ –
Granted	**4,107,330**	**47**	3,786,500	44
Exercised	**(139,680)**	**44**	–	–
Forfeited	**(419,746)**	**47**	(127,050)	44
Balance at end of year	**7,207,354**	**$ 46**	3,659,450	$ 44

Note 24 Stock-Based Compensation *continued*

Stock Appreciation Rights (SARs) *continued*

The following SARs were outstanding as at December 31, 2008:

	Options Outstanding					Options Exercisable		
	Range of Exercise Prices *(dollars)*	Number	Weighted-Average Life *(years)*		Weighted-Average Exercise Price *(dollars)*	Number		Weighted-Average Exercise Price *(dollars)*
$	24 to 40	88,200	6.8	$	33	–	$	–
	41 to 45	3,165,424	5.1		44	718,135		44
	46 to 50	3,771,780	6.1		47	15,875		49
	51 to 55	85,200	5.8		54	18,425		54
	56 to 60	96,750	6.0		58	12,500		57
$	24 to 60	7,207,354	5.7	$	46	764,935	$	45

During 2008, the Company recorded compensation (recovery) expense of $(15) million (2007 – $17 million) relating to SARs.

Performance Share Units (PSUs)

The Company maintains a plan for PSUs for officers and other senior management employees. Under this plan, notional share units are awarded and settled in cash at the end of a three-year period based upon the Company's share price at that time, the value of notional dividends applied during the period and the Company's total shareholder return relative to a peer group of North American industry competitors.

Changes in the number of outstanding PSUs were as follows:

	2008	2007
	Number	Number
Balance at beginning of year	**1,166,044**	1,482,986
Granted	**254,169**	247,476
Redeemed	**(584,137)**	-
Forfeited	**(7,704)**	(564,418)
Balance at end of year	**828,372**	1,166,044

PSUs have a three-year performance period, such that those outstanding at the end of 2008 are related to PSUs issued in 2006, 2007 and 2008 (2006 grant – 346,667; 2007 grant – 236,652; 2008 grant – 245,053). During 2008, the Company recorded compensation (recovery) expense relating to PSUs of $(5) million (2007 – $4 million; 2006 – $(4) million).

Deferred Share Units (DSUs)

The Company maintains a plan for DSUs whereby executive officers are awarded DSUs and/or can elect to receive all or a portion of their annual incentive compensation in the form of DSUs. Under this plan, notional share units are issued for the elected amount, which is based on the then current market price of the Company's common shares. Upon termination or retirement, the units are settled in cash, which includes an amount for the value of notional dividends earned over the period the units were outstanding.

The Company's Board of Directors receives a portion of their compensation in the form of DSUs and can also elect to receive all or a portion of their remaining compensation in the form of DSUs. Under the Director program, notional share units are issued and settled in cash or common shares, including the value of notional dividends, upon ceasing to be a Director.

During 2008, the Company recorded compensation (recovery) expense relating to DSUs of $(16) million (2007 – $4 million; 2006 – $2 million).

Note 25 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 actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The accrued benefit obligations and the fair value of plan assets are measured for accounting purposes at December 31 of each year. The most recent actuarial valuation of the pension plan for funding purposes was as of December 31, 2007 and the next required valuation will be as of December 31, 2010.

The defined contribution plan provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Benefit Plan Expense

	Pension Plans			Other Post-Retirement Plans		
	2008	2007	2006	**2008**	2007	2006
(a) Defined benefit plans						
Employer current service cost	**$ 40**	$ 43	$ 40	**$ 6**	$ 5	$ 4
Interest cost	**95**	90	86	**13**	12	11
Actual return on plan assets	**222**	(8)	(154)	**-**	-	-
Actuarial losses (gains)	**(187)**	(42)	43	**(33)**	13	-
Elements of employee future benefit plan expense before adjustments to recognize the long-term nature of employee future benefit plan expense	**$ 170**	$ 83	$ 15	**$ (14)**	$ 30	$ 15
Difference between actual and expected return on plan assets	**(333)**	(104)	55	**-**	-	-
Difference between actual and recognized actuarial losses in year	**236**	86	8	**35**	(11)	2
Amortization of transitional (asset) obligation	**(7)**	(6)	(5)	**2**	2	2
	$ 66	$ 59	$ 73	**$ 23**	$ 21	$ 19
(b) Defined contribution plans	**27**	22	18			
Total expense	**$ 93**	$ 81	$ 91	**$ 23**	$ 21	$ 19

Benefit Plan Funding

	Pension Plans			Other Post-Retirement Plans		
	2008	2007	2006	**2008**	2007	2006
Defined contribution	**$ 27**	$ 22	$ 18			
Defined benefit	**$ 40**	$ 99	$ 96	**$ 10**	$ 10	$ 10

Financial Status of Defined Benefit Plans

	Pension Plans		Other Post-Retirement Plans	
	2008	2007	**2008**	2007
Fair value of plan assets	**$ 1,232**	$ 1,502	**$ -**	$ -
Accrued benefit obligation	**1,639**	1,784	**231**	255
Funded status – plan deficit[1]	**(407)**	(282)	**(231)**	(255)
Unamortized transitional (asset) obligation	**(5)**	(12)	**9**	11
Unamortized net actuarial losses	**554**	462	**16**	51
Accrued benefit asset (liability)	**$ 142**	$ 168	**$ (206)**	$ (193)

1 The pension and other post-retirement plans included in the financial status information are not fully funded.

Note 25 Employee Future Benefits *continued*

Reconciliation of Plan Assets

	Pension Plans		Other Post-Retirement Plans	
	2008	2007	**2008**	2007
Fair value of plan assets at beginning of year	**$ 1,502**	$ 1,486	**$ –**	$ –
Contributions	**40**	99	**10**	9
Benefits paid	**(85)**	(83)	**(10)**	(9)
Actual return on plan assets	**(222)**	8	**–**	–
Other	**(3)**	(8)	**–**	–
Fair value of plan assets at end of year	**$ 1,232**	$ 1,502	**$ –**	$ –

Reconciliation of Accrued Benefit Obligation

	Pension Plans		Other Post-Retirement Plans	
	2008	2007	**2008**	2007
Accrued benefit obligation at beginning of year	**$ 1,784**	$ 1,786	**$ 255**	$ 235
Current service cost	**40**	43	**6**	5
Interest cost	**95**	90	**13**	12
Benefits paid	**(85)**	(83)	**(10)**	(9)
Actuarial losses (gains)	**(187)**	(42)	**(33)**	12
Other	**(8)**	(10)	**–**	–
Accrued benefit obligation at end of year	**$ 1,639**	$ 1,784	**$ 231**	$ 255

Defined Benefit and Other Post-Retirement Plans Assumptions

	2008	2007	2006
Year-end obligation discount rate[1]	**6.3%**	5.3%	5.0%
Accrued benefit obligation discount rate[1]	**6.3%**	5.3%	5.0%
Long-term rate of return on plan assets	**7.5%**	7.5%	7.5%
Rate of compensation increase, excluding merit increases	**3.3%**	3.3%	3.0%

1 Assumption used in both pension and other post-retirement plans.

Assumed Health and Dental Care Cost Trend Rates

	Trend Rates at December 31,		
	2008	2007	2006
Dental care cost trend rate[1]	**4.0%**	4.0%	3.5%
Health care cost trend rate	**8.0%**	8.0%	8.0%
Health care cost trend rate declines to	**4.5%**	4.5%	4.5%
Year from which the health care cost trend rate remains constant	**2017**	2017	2014

1 Dental care cost trend rate assumed to remain constant.

Sensitivity Analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one percentage-point change in assumed health care cost trend rates would have the following effects for 2008:

	Increase	Decrease
Total service and interest cost	$ 3	$ (2)
Accrued benefit obligation	$ 27	$ (24)

Note 25 Employee Future Benefits *continued*

Plan Assets

Asset Category	Percentage of Plan Assets at December 31, 2008	2007
Equity	**56%**	61%
Bonds	**44%**	39%
	100%	100%

Note 26 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 and short-term notes payable, and shareholders' equity. 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:

		2008		2007
Long-term debt	**$**	**4,746**	$	3,339
Add: Current portion of long-term debt		**3**		2
Total long-term debt	**$**	**4,749**	$	3,341
Add: Short-term notes payable		**–**		109
Debt (A)	**$**	**4,749**	$	3,450
Shareholders' equity		**15,475**		11,870
Debt plus equity (B)	**$**	**20,224**	$	15,320
Cash flow from operating activities (C)	**$**	**6,522**	$	3,339
Debt-to-cash flow from operating activities (A/C) *(times)*		**0.7**		1.0
Debt-to-debt plus equity (A/B)		**23.5%**		22.5%

At December 31, 2008, the debt-to-cash flow from operating activities ratio was within the Company's long-term range of no more than 2.0 times. Debt-to-debt plus equity was below the long-term range of 25% to 35%, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. The Company may exceed long-term ranges for short periods of time, but always with the goal to return back within the long-term ranges.

Financial covenants associated with the Company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The Company complied with all financial covenants for the years ended December 31, 2008 and 2007.

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 repurchase 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 common share commencing with the dividend paid on October 1, 2008. In 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 repurchase up to 5% of its outstanding common shares, subject to certain conditions (Note 23). Due to an increasing capital program, the Company did not repurchase any of its shares in 2008.

Given the recent turmoil in financial markets, the Company continues to monitor its capital management strategy and make adjustments as appropriate. The Company's capital management strategy has not changed significantly from the prior year.

Note 27 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.

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 material 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 from the Company's refined petroleum 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.

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. Senior notes, debentures and capital leases all bear interest at fixed rates. Drawings on the syndicated and demand credit facilities bear interest at floating rates. The Company regularly reviews the mix of floating and fixed-rate debt for consistency with its financing objectives. Interest rate risk from the Company's financial instruments is not significant.

Foreign Currency Exchange Risk

Petro-Canada and its Canadian subsidiaries' functional currency is Canadian (Cdn) dollars, while crude oil, one of the Company's primary products, is priced by reference to U.S. dollar benchmark prices. Therefore, Cdn/U.S. dollar exchange rate fluctuations can have a significant impact on the Company's revenues, crude oil and product purchases, and associated financial instruments.

The Company is also exposed to foreign currency exchange risk from its self-sustaining foreign operations whose functional currency is different from Petro-Canada's functional currency. Gains and losses from the translation of financial instruments within these self-sustaining foreign operations into Canadian dollars are presented as a separate component of other comprehensive income (loss) on the Consolidated Statement of Comprehensive Income.

Note 27 Financial Risks and Financial Instruments *continued*

Financial Risks ***continued***

The Company's outstanding U.S. dollar-denominated long-term debt (Note 20) partially mitigates the exposure to Cdn/U.S. dollar exchange rate fluctuations created from its U.S. dollar-denominated cash flows and other associated financial instruments. In addition, the Company may hold a significant amount of U.S. dollar cash and cash equivalents to meet immediate capital and/or operating funding requirements, and may have significant accounts receivable, other assets, accounts payable and accrued liabilities and other liabilities balances denominated in U.S. dollars. These can create additional exposure to foreign currency exchange risk. At December 31, 2008, the Company had the following U.S. dollar-denominated financial instruments:

		2008 *($US)*
Cash and cash equivalents	$	473
Accounts receivable		1,287
Other assets		11
Accounts payable and accrued liabilities		(338)
Long-term debt		(3,953)
Other liabilities		(493)
	$	(3,013)

In respect of the Company's U.S. dollar-denominated financial instruments above, a 10% change in the Cdn/U.S. dollar exchange rate (1.2246 as at December 31, 2008) would change net earnings by approximately $338 million and other comprehensive income (loss) by approximately $32 million. The Company does not have significant financial instruments denominated in other foreign currencies.

b) Credit Risk

The Company is exposed to credit risk on its financial assets 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 and ensures that no customers represent more than 10% of the Company's consolidated revenues for any period.

The Company's maximum exposure to credit risk at December 31, 2008 is equal to the carrying amount of its financial assets recorded on the Consolidated Balance Sheet. The Company carries sufficient provisions to cover its expected losses arising from credit risk associated with all financial assets. These provisions are not significant.

c) Liquidity Risk

The Company is exposed to liquidity risk from the potential inability to generate or obtain sufficient cash 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.

The Company's financial capacity and flexibility remain strong despite the recent turmoil in the financial markets. This is due to the Company's continuing ability to generate cash flow, access existing cash balances and access significant credit facility capacity requiring no near-term refinancing.

Note 27 Financial Risks and Financial Instruments *continued*

Financial Risks *continued*

The timing of undiscounted cash outflows related to financial liabilities is as follows:

		Within 1 year		1 to 5 years		Thereafter
Accounts payable and accrued liabilities and other liabilities[1]	$	3,186	$	900	$	–
Long-term debt[2]		316		1,265		9,267
	$	3,502	$	2,165	$	9,267

1 Other liabilities includes the Fort Hills purchase obligation (Note 7) and the Libya EPSAs signature bonus (Note 13).
2 Includes debentures, senior notes, capital leases and related interest.

Derivative Contracts

The Company enters into forward contracts and options to reduce exposure to Downstream 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 outstanding derivative contracts and their related fair values at December 31, 2008 were as follows:

	Quantity *(MMbbls)*	Maturity		Average Price *($US/bbl)*		Fair Value
Crude oil purchases	1.5	2009	$	44.22	$	3
Crude oil sales	1.3	2009	$	39.44		(8)
					$	(5)

The fair value positions of outstanding derivative contracts were recorded on the Consolidated Balance Sheet as follows:

		December 31, 2008		December 31, 2007
Accounts receivable	**$**	**1**	$	1
Accounts payable and accrued liabilities	**$**	**(6)**	$	–

The fair value of these derivative contracts is based on quotes provided by brokers, which represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative contracts outstanding at December 31, 2008 to maturity. Gains and losses on these derivative contracts are recorded in investment and other income (expense) (Note 6).

In respect of the Company's outstanding derivative contracts above, a $10 US/bbl change in the price of crude oil would change net earnings by approximately $0.5 million.

Note 27 Financial Risks and Financial Instruments *continued*

Derivative Contracts *continued*

During 2004, the Company entered into a series of derivative contracts for the future sale of Dated Brent crude oil in connection with its acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea. Some derivative contracts matured from July 1, 2007 to December 31, 2007. All remaining outstanding derivative contracts were settled in December 2007. This resulted in the following:

		2007
Unrealized losses at beginning of year	$	(1,481)
Net losses during the year		(535)
Maturities[1]		291
Settlement[2]		1,725
	$	–

1 Derivative contracts that matured from July 1, 2007 to December 31, 2007 resulted in realized losses of $291 million ($193 million after-tax).

2 All remaining outstanding derivative contracts were settled, which resulted in realized losses of $1,725 million ($1,145 million after-tax).

Financial Instruments

The fair values of financial instruments recorded on the Consolidated Balance Sheet are as follows:

	2008				2007			
	Carrying Amount		**Fair Value**		Carrying Amount		Fair Value	
Held-for-trading financial assets								
Cash and cash equivalents	**$**	**1,445**	**$**	**1,445**	$	231	$	231
Loans and receivables								
Accounts receivable[1]		**2,756**		**2,756**		1,931		1,931
Other assets		**32**		**32**		34		34
Other financial liabilities (not held-for-trading)								
Accounts payable and accrued liabilities		**(3,186)**		**(3,186)**		(3,512)		(3,512)
Short-term notes payable		**-**		**-**		(109)		(109)
Long-term debt		**(4,749)**		**(3,868)**		(3,341)		(3,495)
Other liabilities		**(909)**		**(906)**		(380)		(380)
	$	**(4,611)**	**$**	**(3,727)**	$	(5,146)	$	(5,300)

1 Accounts receivable on the Consolidated Balance Sheet at December 31, 2008 includes $88 million (December 31, 2007 – $42 million) of prepaid expenses.

The fair values of held-for-trading financial assets, loans and receivables and accounts payable and accrued liabilities equal or approximate their carrying amounts. The fair values of debentures, senior notes and capital leases are based on publicly quoted market values for instruments with similar terms and risks. The fair values of the Fort Hills purchase obligation and the Libya EPSAs signature bonus obligation, included in other liabilities, reflect expected payout patterns and the Company's estimated cost of debt at year end.

Note 28 Commitments and Contingent Liabilities

Commitments

	2009	2010	2011	2012	2013	Thereafter	Total
Operating leases	$ 484	$ 372	$ 144	$ 123	$ 90	$ 869	$ 2,082
Transportation agreements	197	196	136	119	111	677	1,436
Product purchase/delivery obligations	3,361	1,871	1,371	1,219	699	4,212	12,733
Exploration work commitments	381	186	105	85	–	12	769
Other long-term obligations	661	1,013	587	239	234	1,052	3,786
	$ 5,084	$ 3,638	$ 2,343	$ 1,785	$ 1,134	$ 6,822	$ 20,806

Contingent Liabilities

The Company is involved in litigation and claims in the normal course of operations. In addition, the Company may provide indemnifications, in the normal course of operations, that are often standard contractual terms to counterparties in certain transactions, such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management is of the opinion that any resulting settlements relating to the litigation matters or indemnifications would not materially affect the financial position or results of operations of the Company.

Note 29 Variable Interest Entities

CICA Accounting Guideline 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 VIEs' activities, or is entitled to receive a majority of the VIEs' residual returns, or both. The Company has determined that certain retail licensee and wholesale marketer 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 the 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 significant.

Note 30 Generally Accepted Accounting Principles in the United States

The application of United States GAAP would have the following effects on net earnings as reported:

	Notes	2008	2007[1]	2006[1]
Net earnings from continuing operations, as reported in the Consolidated Statement of Earnings		$ 3,134	$ 2,733	$ 1,588
Adjustments, before income taxes				
Inventories	(a)	–	187	(2)
Accounting for income taxes	(b)	(9)	14	8
Capitalization of interest and related amortization	(d)	42	19	47
Stock-based compensation	(g)	45	(31)	(24)
Exploration mining costs	(c)	(19)	(6)	–
Income taxes on above items		(25)	(41)	8
Net earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy		3,168	2,875	1,625
Net earnings from discontinued operations		–	–	152
Net earnings, as adjusted before cumulative effect of change in accounting policy		3,168	2,875	1,777
Cumulative effect of change in accounting policy, net of tax	(g)	–	–	(14)
Net earnings, as adjusted		$ 3,168	$ 2,875	$ 1,763
Earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy per share				
Basic		$ 6.54	$ 5.88	$ 3.22
Diluted		$ 6.50	$ 5.82	$ 3.19
Earnings, as adjusted before cumulative effect of change in accounting policy per share				
Basic		$ 6.54	$ 5.88	$ 3.53
Diluted		$ 6.50	$ 5.82	$ 3.49
Earnings, as adjusted per share				
Basic		$ 6.54	$ 5.88	$ 3.50
Diluted		$ 6.50	$ 5.82	$ 3.46

1 Prior period figures have been restated as a result of the Company adopting a FIFO inventory valuation basis (Note (a)).

The application of United States GAAP would have the following effects on comprehensive income as reported:

	Notes	2008	2007	2006
Comprehensive income, net of tax, as reported on the Consolidated Statement of Comprehensive Income		$ 3,348	$ 2,473	$ 2,103
Adjustments to net earnings, net of tax		34	(1)	7
Adjustments to other comprehensive income (loss), net of tax				
Additional pension liability	(f)	(44)	(52)	42
Unrealized gain (loss) on translation of foreign currency denominated additional capitalized interest	(d)	(7)	(20)	6
Comprehensive income, net of tax, as adjusted		$ 3,331	$ 2,400	$ 2,158

Note 30 Generally Accepted Accounting Principles in the United States *continued*

The application of United States GAAP would have the following effects on the Consolidated Balance Sheet as reported:

		December 31, 2008		December 31, 2007	
	Notes	As Reported	United States GAAP	As Reported	United States GAAP[1]
Current assets	(a)	$ 5,603	$ 5,603	$ 3,178	$ 3,990
Property, plant and equipment, net	(b, c, d)	23,485	24,106	19,497	20,112
Goodwill	(b)	852	831	731	710
Other assets	(f, h)	437	411	446	384
Current liabilities	(g)	4,207	4,229	3,623	3,705
Long-term debt	(h)	4,746	4,862	3,339	3,445
Other liabilities	(f, g)	1,240	1,679	717	1,056
Asset retirement obligations		1,527	1,527	1,234	1,234
Future income taxes	(a, b, c, d, f, g)	3,182	3,190	3,069	3,324
Common shares		1,388	1,388	1,365	1,365
Contributed surplus	(e)	22	793	24	795
Retained earnings	(e)	14,062	13,720	10,692	10,872
Accumulated other comprehensive income (loss)	(d, f)	$ 3	$ (437)	$ (211)	$ (600)

1 Prior period figures have been restated as a result of the Company adopting a FIFO inventory valuation basis (Note (a)).

The Company's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements:

a) Inventories

The Company adopted CICA Section 3031, *Inventories*, on January 1, 2008, valuing inventory on a FIFO basis and electing to adjust 2008 opening retained earnings in accordance with transitional provisions of the new accounting standard (Note 3). The Company also adopted this inventory valuation policy for United States GAAP, which requires retrospective accounting treatment for this change in accounting policy. As a result, the Company has restated certain prior year comparative figures.

b) Income Taxes

The liability method followed by the Company differs from United States GAAP due to the application of transitional provisions upon adoption and the use of substantively enacted versus enacted rates.

c) Property, Plant and Equipment

Under Canadian GAAP, exploration costs for mining properties are capitalized when such costs have the characteristics of property, plant and equipment. Under United States GAAP, exploration costs for mining properties are expensed until proved and probable reserves have been established by a feasibility study.

Note 30 **Generally Accepted Accounting Principles in the United States** *continued*

d) Interest Capitalization

The Company capitalizes interest attributable to the construction of major new facilities under both Canadian and United States GAAP, but uses different capitalization methodologies under each. Under United States GAAP, the amount of interest capitalized for the period is the product of the average accumulated capitalized costs and the weighted-average interest rate applicable to all borrowings outstanding during the period. However, under Canadian GAAP, the amount of interest capitalized is calculated using the same formula except that the average accumulated capitalized costs are first multiplied by the Company's average corporate debt to equity ratio.

e) Contributed Surplus

In prior years, the Company transferred $1,122 million from contributed surplus to the accumulated deficit. United States GAAP does not permit these transfers. As a result of this difference, under United States GAAP, the excess of the purchase price over the carrying amount of shares repurchased under the Company's NCIB program has been recorded as a reduction of contributed surplus. Under Canadian GAAP, this excess cost has been recorded as a reduction of both contributed surplus and retained earnings.

f) Pensions and Other Post-Retirement Benefits

United States GAAP requires the Company to recognize the overfunded or underfunded status of its defined benefit post-retirement plans, measured as the difference between the fair value of plan assets and the accrued benefit obligation, as an asset or liability on its balance sheet. Changes to the funding status in the year are recorded through other comprehensive income (loss), net of tax. Canadian GAAP currently does not require the Company to recognize the funded status of these plans on the Consolidated Balance Sheet.

g) Stock-Based Compensation

United States GAAP requires compensation costs related to share-based awards classified as liabilities to be recognized as an expense at fair value with re-measurement to fair value each period. Under Canadian GAAP, the Company recognizes compensation cost for stock options, which provides the holder the right to exercise the stock option or surrender the option for cash payment based on the intrinsic value at each period end.

h) Deferred Financing Costs

The Company adopted CICA Section 3855, *Financial Instruments – Recognition and Measurement*, on January 1, 2007. As a result, transaction costs and premiums or discounts directly attributable to the issuance of long-term debt are now added to the fair value of the debt upon initial recognition. Previously, these amounts were deferred and presented as assets. This is still the prescribed treatment under United States GAAP.

i) Cash Flow Information

The application of United States GAAP would not have a material effect on cash flow from total operating, investing, or financing activities on the Consolidated Statement of Cash Flows.

j) Fair Value Measurements and Fair Value Option

The Financial Accounting Standards Board (FASB) issued Statement 157, *Fair Value Measurements*, and Statement 159, *Fair Value Option for Financial Assets and Financial Liabilities*, both effective for the Company's 2008 fiscal year. The application of these Statements did not have a significant impact on the Company's Consolidated Financial Statements under United States GAAP.

Note 31 Recent Accounting Pronouncements

Canadian

Goodwill and Intangible Assets

The AcSB has issued CICA Section 3064, *Goodwill and Intangible Assets*, and as a result has withdrawn CICA Section 3062, *Goodwill and Other Intangible Assets*, and CICA Section 3450, *Research and Development Costs*. This new standard reinforces the principle-based approach to the recognition of costs as assets in accordance with the AcSB's definition of an asset. This standard is effective for fiscal years beginning on or after January 1, 2009. There is no material impact on the Company's Consolidated Financial Statements.

Business Combinations

In January 2009, the AcSB issued CICA Section 1582, *Business Combinations*, which replaces the existing Section 1581 of the same name. This standard mandates that all future business combinations be accounted for as a purchase by one party of another, and that all assets, liabilities, contingent consideration and non-controlling interest of the acquiree be recorded at fair value. Gains on bargain purchases are to be recognized in net earnings, and all acquisition costs expensed. This standard is equivalent to the IFRS on business combinations. This standard is effective for fiscal years beginning on or after January 1, 2011, with early application permitted, and will likely impact future Consolidated Financial Statements should the Company engage in business combinations.

United States

Business Combinations

In December 2007, the FASB issued Revised Statement 141R, *Business Combinations*. This standard is identical to CICA Section 1582, *Business Combinations*, except that it is effective for fiscal years beginning after December 15, 2008. As with CICA Section 1582, *Business Combinations*, this standard will likely impact future Consolidated Financial Statements should the Company engage in business combinations.

End of Financial Statements