FINANCIAL STATEMENTS

A strong balance sheet
allows us to fund our capital programs
and pursue strategic opportunities.

Statements

PART II

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Controls and Procedures

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ITEM 8.

REPORT OF MANAGEMENT

February 11, 2009

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the consolidated financial statements, as well as the financial reporting process that gives rise to such consolidated financial statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our consolidated financial statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors is responsible for reviewing and approving the consolidated financial statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our petroleum, natural gas and Syncrude reserves, and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors and includes three directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Marvin F. Romanow"
President and Chief Executive Officer

(signed) "Kevin J. Reinhart"
Senior Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the accompanying consolidated balance sheets of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, cash flows, shareholders' equity and comprehensive income for each of the years in the three year 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 Nexen Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2008 in accordance 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 11, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 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 1(u) to the consolidated financial statements. Our report to the Board of Directors and shareholders on the consolidated financial statements of the Company dated February 11, 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 changes are properly accounted for and adequately disclosed in the financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 2009

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions, except per share amounts	**2008**	**2007**	**2006**
Revenues and Other Income			
Net Sales	7,424	5,583	3,936
Marketing and Other (Note 17)	813	1,021	1,450
	8,237	6,604	5,386
Expenses			
Operating	1,335	1,165	955
Depreciation, Depletion, Amortization and Impairment (Note 4)	2,014	1,767	1,124
Transportation and Other	967	908	1,041
General and Administrative	257	374	555
Exploration	402	326	362
Interest (Note 10)	94	168	53
	5,069	4,708	4,090
Income before Provision for Income Taxes	3,168	1,896	1,296
Provision for Income Taxes (Note 18)			
Current	859	434	368
Future	598	358	315
	1,457	792	683
Net Income before Non-Controlling Interests	1,711	1,104	613
Net Income (Loss) Attributable to Non-Controlling Interests	(4)	18	12
Net Income	**1,715**	**1,086**	**601**
Earnings Per Common Share ($/share) (Note 19)			
Basic	3.26	2.06	1.15
Diluted	3.22	2.02	1.12

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

CONSOLIDATED BALANCE SHEET

DECEMBER 31, 2008 AND 2007

Cdn$ millions, except share amounts	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	2,003	206
Restricted Cash	103	203
Accounts Receivable (Note 2)	3,163	3,502
Inventories and Supplies (Note 3)	484	659
Other	169	89
Total Current Assets	5,922	4,659
Property, Plant and Equipment (Note 4)	14,922	12,498
Goodwill	390	326
Future Income Tax Assets (Note 18)	351	268
Deferred Charges and Other Assets (Note 6)	570	324
TOTAL ASSETS	**22,155**	**18,075**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 9)	3,326	4,180
Accrued Interest Payable	67	54
Dividends Payable	26	13
Total Current Liabilities	3,419	4,247
Long-Term Debt (Note 10)	6,578	4,610
Future Income Tax Liabilities (Note 18)	2,619	2,290
Asset Retirement Obligations (Note 12)	1,024	792
Deferred Credits and Other Liabilities (Note 13)	1,324	459
Non-Controlling Interests	52	67
Shareholders' Equity (Note 15)		
Common Shares, no par value Authorized: Unlimited Outstanding: 2008—519,448,590 shares 2007—528,304,813 shares	981	917
Contributed Surplus	2	3
Retained Earnings	6,290	4,983
Accumulated Other Comprehensive Loss	(134)	(293)
Total Shareholders' Equity	7,139	5,610
Commitments, Contingencies and Guarantees (Notes 16 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**22,155**	**18,075**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Marvin F. Romanow"
Director

(signed) "Thomas C. O'Neill"
Director

NEXEN INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	2008	2007	2006
Operating Activities			
Net Income	1,715	1,086	601
Charges and Credits to Income not Involving Cash (Note 20a)	2,136	2,073	1,629
Exploration Expense	402	326	362
Changes in Non-Cash Working Capital (Note 20b)	119	(348)	(177)
Other	(18)	(307)	(41)
	4,354	2,830	2,374
Financing Activities			
Proceeds from Long-Term Notes	–	1,660	–
Repayment of Medium-Term Notes and Debentures	(125)	(150)	(93)
Proceeds from (Repayment of) Term Credit Facilities, Net	803	(697)	1,044
Proceeds from (Repayment of) Short-Term Borrowings, Net	(4)	(150)	160
Proceeds from Canexus Notes	51	–	–
Proceeds from (Repayment of) Term Credit Facilities of Canexus, Net	(20)	60	2
Dividends on Common Shares	(92)	(53)	(52)
Distributions Paid to Non-Controlling Interests	(17)	(28)	(28)
Issue of Common Shares and Exercise of Tandem Options for Shares (Note 15b)	64	56	48
Repurchase of Common Shares for Cancellation (Note 15b)	(338)	–	–
Other	–	(21)	–
	322	677	1,081
Investing Activities			
Capital Expenditures			
Exploration and Development	(2,895)	(3,132)	(3,198)
Proved Property Acquisitions	(22)	(151)	(13)
Chemicals, Corporate and Other	(149)	(118)	(119)
Business Acquisitions, Net of Cash Acquired (Note 5)	–	–	(78)
Proceeds on Disposition of Assets	6	4	27
Changes in Non-Cash Working Capital (Note 20b)	(124)	130	134
Changes in Restricted Cash	106	(16)	(127)
Other	(111)	2	(14)
	(3,189)	(3,281)	(3,388)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	310	(121)	(14)
Increase in Cash and Cash Equivalents	1,797	105	53
Cash and Cash Equivalents, Beginning of Year	206	101	48
Cash and Cash Equivalents, End of Year	**2,003**	**206**	**101**

Cash and cash equivalents at December 31, 2008 consists of cash of $355 million and short–term investments of $1,648 million.

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	2008	2007	2006
Common Shares, Beginning of Year	917	821	732
Issue of Common Shares	41	32	32
Exercise of Tandem Options for Shares	23	24	16
Accrued Liability Relating to Tandem Options Exercised for Common Shares	22	40	41
Repurchased Under Normal Course Issuer Bid (Note 15b)	(22)	–	–
End of Year	**981**	**917**	**821**
Contributed Surplus, Beginning of Year	3	4	2
Stock-Based Compensation Expense	–	1	2
Exercise of Tandem Options	(1)	(2)	–
End of Year	**2**	**3**	**4**
Retained Earnings, Beginning of Year	4,983	3,972	3,423
Net Income	1,715	1,086	601
Dividends on Common Shares	(92)	(53)	(52)
Transition Adjustment on Adoption of New Inventory Standard	–	(22)	–
Repurchase of Common Shares for Cancellation (Note 15b)	(316)	–	–
End of Year	**6,290**	**4,983**	**3,972**
Accumulated Other Comprehensive Loss, Beginning of Year	(293)	(161)	(161)
Opening Derivatives Designated as Cash Flow Hedges	–	61	–
Other Comprehensive Income (Loss)	159	(193)	–
End of Year [1]	**(134)**	**(293)**	**(161)**

1 Includes unrealized foreign currency translation adjustment.

NEXEN INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	2008	2007	2006
Net Income	1,715	1,086	601
Other Comprehensive Income (Loss), net of income taxes:			
Foreign Currency Translation Adjustment:			
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	1,228	(867)	16
Net Gains (Losses) on Debt Hedges of Self-Sustaining Foreign Operations [1]	(1,062)	738	(20)
Realized Translation Adjustments Recognized in Net Income	(7)	(3)	4
Cash Flow Hedges:			
Realized Mark-to-Market Gains Recognized in Net Income	–	(61)	–
Other Comprehensive Income (Loss)	159	(193)	–
Comprehensive Income	**1,874**	**893**	**601**

1 Net of income tax recovery for the year ended December 31, 2008 of $145 million (2007—$97 million expense; 2006—$12 million recovery).

See accompanying notes to Consolidated Financial Statements.

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 23.

(a) Consolidation

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus Limited Partnership and its subsidiaries (Canexus), are wholly owned. All intercompany accounts and transactions are eliminated upon consolidation.

We have a 63.5% interest in Canexus represented by 56.6 million Exchangeable LP Units. We have the right to nominate a majority of the members of the Board of Directors, who have the power to determine the strategic operating, investing and financing policies of Canexus. Through our majority ownership interest and the ability to elect the majority of the members of the board, Nexen holds effective control over Canexus. All assets, liabilities and results of operations of Canexus are consolidated and have been included in our Consolidated Financial Statements. Non-Nexen ownership interests in Canexus are shown as non-controlling interests.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under current US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(b) Use of estimates

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy, and the determination of proved reserves. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(c) Cash and cash equivalents

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase. These investments are recorded at cost, which approximates fair value.

(d) Restricted cash

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts.

(e) Accounts receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(o)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(f) Inventories and supplies

Inventories and supplies, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion, directly or indirectly incurred in bringing the inventory to its existing condition.

Effective October 1, 2007, commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, as measured by the one-month forward price, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(g) Property, plant and equipment (PP&E)

PP&E is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. Costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the costs are reclassified to proved property costs. Exploration drilling costs are capitalized as suspended exploration well costs pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized if a determination is made that a sufficient quantity of reserves have been found and sufficient progress is being made to assess the reserves and the economic and operating viability. All other exploration costs, including geological and geophysical and annual lease rentals, are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established, and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(h) Depreciation, depletion, amortization and impairment (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When the inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs using the straight-line method based on the estimated useful lives of the assets, which range from 3 to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of estimated undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future net cash flows, discounted for the time value of money, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(i) Capitalized interest

We capitalize interest on major development projects until the project is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(j) Carried interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(k) Goodwill

Our goodwill is attributable to our energy marketing and UK operating segments. It has been recorded at cost and is not amortized. We test goodwill for impairment at least annually or whenever events or circumstances indicate that goodwill is impaired. We base our test on estimated future net cash flows of the reporting unit. If goodwill is impaired we reduce the carrying value to estimated fair value and an impairment loss is recorded in net income. No significant impairments arose from the December 2008 and the December 2007 annual tests.

(l) Financial instruments and hedging activities

All financial assets and liabilities are recognized on the balance sheet when we become a party to the contractual provisions of the instrument and are initially recognized at fair value. Subsequent measurement of the financial instruments is based on their classification. We have classified each financial instrument into one of the following categories: financial assets and financial liabilities held for trading; loans or receivables; financial assets held to maturity; financial assets available for sale; and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in very limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, accrued interest payable, dividends payable, short-term borrowings and long-term debt. Transaction costs are included in net income when incurred for these types of financial instruments except for short-term borrowings and long-term debt. These transaction costs are included with the initial fair value and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

Derivatives related to non-trading activities

We use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Notes 7 and 8). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other income during the period of change unless the requirements for hedge accounting are met.

Derivatives related to trading activities

Our energy marketing operation uses derivative instruments for marketing and trading natural gas, crude oil, natural gas liquids and power including: commodity contracts settled with physical delivery; exchange-traded futures and options; and non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change. The fair value of these instruments is included with accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond twelve months, we include them with deferred charges and other assets or deferred credits and other liabilities.

Hedge accounting

Hedge accounting may be used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income with any ineffectiveness recognized in marketing and other income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Nexen had no cash flow or fair value hedges in place at December 31, 2008 or 2007.

Comprehensive income

Comprehensive income consists of net income and other comprehensive income (OCI). OCI includes gains and losses resulting from the foreign exchange translation of our net investments in self-sustaining foreign operations and the effective portion of derivatives used as a hedging item in a cash flow hedge or net investment hedge. Accumulated other comprehensive income (AOCI) is a separate component of shareholders' equity comprised of the cumulative amounts of OCI. Amounts included in AOCI are reclassified to income when realized.

(m) Asset retirement obligations

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The obligation is accreted through DD&A expense until it is expected to settle and the cost is amortized through DD&A expense over the life of the respective asset. The fair value of the obligation is estimated by discounting expected future cash flows estimated to settle the asset retirement obligation using a weighted-average, credit-adjusted risk free interest rate. Nexen recognizes period-to-period changes due to the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

(n) Pension and other post-retirement benefits

Our employee post-retirement benefit programs consist of contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs.

For our defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%.

During the year, we changed our measurement date for defined benefit plans from October 31 to December 31. This change was applied prospectively and did not have a material impact on our financial statements.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

(o) Revenue recognition

Oil and gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil and natural gas reaches the end of the pipeline. For our other international operations, including the UK, our customers take title when crude oil is loaded onto tankers. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(j).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Energy marketing

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our energy marketing operation are stated at fair value on the balance sheet (see Note 1(l)). We record any change in fair value as a gain or loss in marketing and other income unless requirements for hedge accounting are met.

Any margin earned by our energy marketing operation on the sale of our proprietary oil and gas production is included in marketing and other. Sales of our proprietary production are recorded at monthly average market-based prices and reported in our oil and gas segments. Intercompany profits and losses between segments are eliminated.

We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have a legally enforceable right and intention to offset.

(p) Foreign currency translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt (excluding debt related to Canexus) as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other income in the Consolidated Statement of Income.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in marketing and other income in the Consolidated Statement of Income.

(q) Transportation

We pay to transport the crude oil, natural gas and chemical products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as transportation and other expense. Amounts billed to our customers are presented within marketing and other income. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(r) Leases

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases and the related assets are included with PP&E and are amortized on a straight-line basis over the period of expected use, consistent with other PP&E. Rental payments under operating leases are expensed as incurred.

(s) Stock-based compensation

Our stock-based compensation consists of tandem option (TOPs) and stock appreciation right (StARs) plans.

Tandem options to purchase common shares are granted to directors, officers and employees at the discretion of the Board of Directors. Each tandem option gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market value of the common share over the exercise price. Options granted prior to February 2001 vest over four years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market value.

We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

Under our StARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan. The total StARs granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals market value. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

(t) Income taxes

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(u) Changes in accounting principles

Capital disclosures

On January 1, 2008, we prospectively adopted Canadian Institute of Chartered Accountants (CICA) Section 1535 *Capital Disclosures* issued by the Canadian Accounting Standards Board (AcSB). This Section establishes standards for disclosing information about an entity's objectives, policies and processes for managing its capital structure. The disclosures have been included in Note 11.

Financial instruments disclosures and presentation

On January 1, 2008, we prospectively adopted the following new standards issued by the AcSB: *Financial Instruments—Disclosure* (Section 3862) and *Financial Instruments—Presentation* (Section 3863). These accounting standards replaced *Financial Instruments—Disclosure and Presentation* (Section 3861). The disclosures required by Section 3862 and 3863 provide additional information on the risks associated with our financial instruments and how we manage those risks. The additional disclosures required by these standards are provided in Notes 7 and 8.

New accounting pronouncements

In February 2008, the AcSB confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been set up to manage this transition and to ensure successful implementation within the required timeframe.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for recognizing assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. We plan to adopt this standard prospectively effective January 1, 2009 and do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. We plan to adopt these standards effective January 1, 2009 and do not expect the adoption will have a material impact on our results of operations or financial position.

2. ACCOUNTS RECEIVABLE

	2008	2007
Trade		
Energy Marketing	2,256	2,501
Oil and Gas	639	819
Chemicals and Other	68	60
	2,963	3,380
Non-Trade	270	132
	3,233	3,512
Allowance for Doubtful Receivables	(70)	(10)
Total	**3,163**	**3,502**

3. INVENTORIES AND SUPPLIES

	2008	2007
Finished Products		
Energy Marketing	384	577
Oil and Gas	17	14
Chemicals and Other	16	13
	417	604
Work in Process	6	3
Field Supplies	61	52
Total	**484**	**659**

4. PROPERTY, PLANT AND EQUIPMENT

	2008			2007		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	899	781	118	701	590	111
Yemen—Carried Interest	1,909	1,829	80	1,477	1,360	117
Canada [1]	8,134	1,786	6,348	6,736	1,597	5,139
US	4,398	2,702	1,696	3,069	1,765	1,304
UK	6,532	2,159	4,373	4,723	908	3,815
Other Countries	554	113	441	263	77	186
	22,426	9,370	13,056	16,969	6,297	10,672
Energy Marketing	246	76	170	246	62	184
Syncrude	1,372	236	1,136	1,332	205	1,127
Chemicals	940	507	433	831	463	368
Corporate and Other	331	204	127	315	168	147
Total	**25,315**	**10,393**	**14,922**	**19,693**	**7,195**	**12,498**

1 Includes capitalized costs related to our insitu oil sands (Long Lake and future phases) of $4,742 million (2007—$3,695 million).

The above table includes capitalized costs of $7,386 million (2007—$5,828 million) relating to unproved properties and projects under construction or development. These costs are currently not being depreciated, depleted or amortized, however we expect to begin amortizing the capitalized costs of Long Lake Phase 1 in early 2009. Our insitu oil sands capitalized costs in Canada include $1,874 million related to the Phase 1 upgrader (2007—$1,711 million), $1,325 million for Phase 1 SAGD and cogeneration facilities (2007—$1,026 million); and $1,543 million related to capitalized interest and future phases (2007—$958 million).

Depreciation, depletion, amortization and impairment

In 2008, our DD&A expense includes $568 million of impairment expense relating to oil and gas properties in the Gulf of Mexico and North Sea. These properties were written down to their estimated fair value based on their estimated total future discounted net cash flows.

In the Gulf of Mexico, we reduced the carrying value of four shelf properties by $143 million, primarily as a result of low oil and gas prices and higher estimated asset remediation costs. These late-life, mature properties have a shorter production horizon, and therefore are sensitive to near-term commodity prices and to higher abandonment costs. Inflationary pressures in the oil and gas industry increased the estimated future costs to remediate the assets. At Green Canyon 6, we reduced the carrying value of our assets by $107 million to reflect the impact of Hurricane Ike which destroyed a third-party production platform in the third quarter of 2008. This resulted in unexpected and uninsured costs to rebuild facilities.

In the North Sea, we reduced the carrying value of our Ettrick project by $256 million, primarily due to higher costs and lower reserve estimates following drilling and testing activities. We also expensed costs of $62 million related to our Selkirk discovery as we currently have no firm plans to continue with development.

In 2007, our DD&A expense includes $366 million of impairment expense primarily related to our Aspen, Vermilion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our investment in development drilling resulted in negative reserve revisions. At Vermilion 320/340 and West Cameron 170, negative reserve revisions primarily related to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. These properties were written down to their estimated fair value equal to estimated total future discounted net cash flows.

Research and development

In 2008, we incurred $30 million (2007—$40 million) in connection with research and development activities related to developing new technologies for increasing oil recoveries. Research costs of $27 million (2007—$38 million) were included in other expense on the Consolidated Statement of Income. The development costs have been deferred and are included in PP&E.

	2008	2007
Beginning of Year	30	28
Deferred in the Year	3	2
Amortized in the Year	–	–
End of Year	**33**	**30**

Suspended exploration well costs

The following table shows the changes in capitalized exploratory well costs during the years ended December 31, 2008 and 2007, and does not include amounts that were initially capitalized and subsequently expensed in the same period.

	2008	2007
Beginning of Year	326	226
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	254	215
Capitalized Exploratory Well Costs Charged to Expense	(81)	(10)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(29)	(74)
Effects of Foreign Exchange Rate Changes	48	(31)
End of Year	**518**	**326**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	2008	2007
Capitalized for a Period of One Year or Less	239	202
Capitalized for a Period of Greater than One Year	279	124
Total	**518**	**326**
Number of Projects with Exploratory Well Costs Capitalized for a Period Greater than One Year	7	5

As at December 31, 2008, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico ($120 million), our coalbed methane exploratory activities in Canada ($70 million), three exploratory blocks in the North Sea ($67 million), and our interest in an exploratory block offshore Nigeria ($22 million). These costs relate to projects with exploration wells for which we have not been able to record proved reserves. We are assessing all of these wells and projects, and are working with our partners to prepare development plans, drill additional appraisal wells or to assess commercial viability.

5. BUSINESS ACQUISITIONS

In 2006, we completed business acquisitions related to our energy marketing group for $78 million, net of cash acquired. These acquisitions were accounted for using the purchase method of accounting. The assets and liabilities purchased were primarily working capital and we recorded goodwill of $12 million.

6. DEFERRED CHARGES AND OTHER ASSETS

	2008	2007
Crude Oil Put Options and Natural Gas Swaps (Note 7b)	234	1
Long-Term Energy Marketing Derivative Contracts (Note 7a)	217	248
Long-Term Capital Prepayments	61	9
Asset Retirement Remediation Fund	9	13
Other	49	53
Total	**570**	**324**

7. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments including accounts receivable, accounts payable, income taxes payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities, and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included with amounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At December 31, 2008, the estimated fair value of our long-term debt was $5,686 million (December 31, 2007—$4,692 million) as compared to the carrying value of $6,578 million (December 31, 2007—$4,610 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers. The recent economic crisis impacted market prices for corporate bonds and as a result, the estimated fair value of our long-term debt was lower in the fourth quarter of 2008.

Derivatives

(a) Total carrying value of derivative contracts related to trading activities

The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	2008	2007
Accounts Receivable	755	334
Deferred Charges and Other Assets [1]	217	248
Total Trading Derivative Assets	**972**	**582**
Accounts Payable and Accrued Liabilities	615	413
Deferred Credits and Other Liabilities [1]	294	163
Total Trading Derivative Liabilities	**909**	**576**
Total Net Trading Derivative Assets [2]	**63**	**6**

1 *These derivative contracts settle beyond 12 months and are considered non-current.*

2 *Comprised of $122 million (2007—$15 million) related to commodity contracts and net losses of $59 million (2007—$9 million loss) related to US-dollar and Euro forward contracts and swaps.*

(b) Total carrying value of derivative contracts related to non-trading activities

The fair value and carrying amounts related to derivative instruments related to non-trading activities are as follows:

	2008	2007
Accounts Receivable	6	–
Deferred Charges and Other Assets [1]	234	1
Total Non-Trading Derivative Assets	**240**	**1**
Accounts Payable and Accrued Liabilities	21	28
Deferred Credits and Other Liabilities [1]	26	51
Total Non-Trading Derivative Liabilities	**47**	**79**
Total Net Non-Trading Derivatives Assets (Liabilities)	**193**	**(78)**

1 *These derivative contracts settle beyond 12 months and are considered non-current.*

Crude oil put options

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production for $14 million. These options establish an annual average Dated Brent floor price of US$60/bbl on these volumes. In September 2008, Lehman Brothers filed for bankruptcy protection. This impacts 25,000 bbls/d of our 2009 put options and the carrying value of these put options has been reduced to nil.

In 2007, we purchased put options on approximately 100,000 bbls/d of our 2008 crude oil production for $24 million. These options established an annual average Dated Brent floor price of US$50/bbl on these volumes. These put options expired out of the money.

The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third party brokers, which were validated with observable market data to the extent possible. Any change in fair value is included in marketing and other income.

	Notional Volumes (bbls/d)	**Term**	**Average Floor Price** (US$/bbl)	**Fair Value** (Cdn$ millions)
Dated Brent Crude Oil Put Options	45,000	2009	60	233
Dated Brent Crude Oil Put Options	25,000	2009	60	–

Fixed-price natural gas contracts and natural gas swaps

We have fixed-price natural gas sales contracts and offsetting natural gas swaps that are not part of our trading activities. These sales contracts and swaps are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Any change in fair value is included in marketing and other income.

	Notional Volumes (Gj/d)	**Term**	**Average Floor Price** ($/Gj)	**Fair Value** (Cdn$ millions)
Fixed-Price Natural Gas Contracts	15,514	2009	2.28	(21)
	15,514	2010	2.28	(26)
Natural Gas Swaps	15,514	2009	7.60	6
	15,514	2010	7.60	1
				(40)

(c) Fair value of derivatives

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices, and if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated, or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net short position and the bid price when we have a net long position. This adjustment reflects an estimated exit price and incorporates the impact of liquidity when the bid-ask spread widens in less liquid markets. We incorporate the credit risk associated with counterparty default, as well as our own credit risk, into our estimates of fair value.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those which have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value for our trading and non-trading activities as at December 31, 2008. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Net Derivatives	Level 1	Level 2	Level 3	Total
Trading Derivatives	13	132	(82)	**63**
Non-Trading Derivatives	–	193	–	**193**
Total	**13**	**325**	**(82)**	**256**

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the year ended December 31, 2008 is provided below:

	Level 3
Beginning of Year	(7)
Realized and unrealized gains (losses)	(64)
Purchases, issuances and settlements	(9)
Transfers in and/or out of Level 3	(2)
End of Year	**(82)**
Unsettled gains (losses) relating to instruments still held as of December 31, 2008	16

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

8. RISK MANAGEMENT

(a) Market risk

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market risk exposures.

The following market risk discussion relates primarily to commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes also may affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of near-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the world including crude oil, natural gas, electricity and other commodities. We do this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers.

In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

We also seek to profit from our views on the future movement of energy commodity pricing relationships, primarily between different locations, time periods or qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions. We may also carry exposures to the absolute change in commodity prices based on our market views or as a consequence of managing our physical and financial positions on a day to day basis.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions, or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets and may apply to nearer term positions. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available, and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year end, annual high, annual low and average VaR amounts are as follows:

Value-at-Risk *(Cdn$ millions)*	**2008**	**2007**
Year End	25	26
High	40	38
Low	19	24
Average	30	30

If market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

In our oil and gas operations, we manage our exposure to fluctuations between the US and Canadian dollar by maintaining our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. At December 31, 2008, we had US$5,432 million of long-term debt issued in US dollars and a one cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $52 million, before income tax.

We also have exposures to currencies other than the US dollar including a portion of our UK operating expenses, capital spending and future asset retirement obligations which are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies including Canadian and US dollars, British pounds and Euros. We actively manage significant currency exposures using forward contracts and swaps.

(b) Credit risk

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Approximately 71% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. During 2008, we have taken the following specific actions for certain counterparties deemed to be at higher risk of non-performance:

- ceased trading activities;
- significantly reduced and, in some cases, revoked credit privileges;
- redirected business to i) exchanges or clearing houses; and ii) entities with physical-based operations;
- increased "set off" arrangements with counterparties; and
- increased collateral and margining requirements where possible.

At December 31, 2008, only one counterparty individually made up more than 10% of our credit exposure. This counterparty is a major integrated oil company with a strong investment grade rating. No other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating.

Credit Rating	2008	2007
A or higher	65%	68%
BBB	29%	27%
Non-Investment Grade	6%	5%
Total	**100%**	**100%**

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as accounts receivable, cash and cash equivalents, restricted cash, as well as the fair value of derivative financial assets. In September 2008, Lehman Brothers filed for bankruptcy protection and our exposure at the time was approximately $39 million. This amount was provided for even though we continue to pursue recovery. We also provided an additional $15 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at December 31, 2008 includes $90 million of cash and $311 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(c) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due, and to operate in our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At December 31, 2008, we had about $4.5 billion of cash and available committed lines of credit (US$3.7 billion). This includes $2 billion of cash and cash equivalents on hand. Of this amount, approximately US$1 billion was a result of draws made on our term credit facilities, which were used for an internal reorganization and financing of our North Sea assets. In addition, we have undrawn term credit facilities of $2.5 billion (US$2.1 billion), of which $381 million (US$311 million) was supporting letters of credit at December 31, 2008. These facilities are available until 2012. We also have $613 million (US$501 million) of undrawn, uncommitted credit facilities, of which $29 million (US$24 million) was supporting letters of credit at year end. Subsequent to year end, we used $735 million of our available liquidity to acquire an additional 15% interest in the Long Lake Project.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2008:

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Long-Term Debt	6,652	–	223	1,898	4,531
Interest on Long-Term Debt [1]	7,611	331	662	657	5,961
Total	**14,263**	**331**	**885**	**2,555**	**10,492**

1 *Excludes interest on term credit facilities of $3.7 billion (US$3.1 billion) and Canexus term credit facilities of $420 million (US$343 million) as the amounts drawn on the facilities fluctuate. Based on amounts drawn at December 31, 2008 and existing variable interest rates, we would be required to pay $19 million per year until the outstanding amounts on the term credit facilities are repaid.*

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Trading Derivatives	909	615	264	25	5
Non-Trading Derivatives	47	21	26	–	–
Total	**956**	**636**	**290**	**25**	**5**

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. Based on contracts in place and commodity prices at December 31, 2008, we could be required to post collateral of up to $1.3 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. In the event of a ratings downgrade, we have trading inventories and receivables that can be quickly monetized as well as significant undrawn credit facilities.

At December 31, 2008, collateral we have posted with counterparties includes $60 million of cash and $194 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. If there is a default, the cash is retained.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $103 million (December 31, 2007—$203 million), which have been included in restricted cash.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2008	2007
Accrued Payables	2,033	2,546
Energy Marketing Derivative Contracts (Note 7a)	615	413
Trade Payables	303	578
Stock-based Compensation	97	393
Income Taxes Payable	69	45
Other	209	205
Total	**3,326**	**4,180**

10. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	2008	2007
Medium-Term Notes, due 2008 (a)	–	125
Canexus Term Credit Facilities, due 2011 (US$182 million drawn) (b)	223	202
Term Credit Facilities, due 2012 (US$1 billion drawn) (c)	1,225	211
Canexus Notes, due 2013 (US$50 million) (d)	61	–
Notes, due 2013 (US$500 million) (e)	612	494
Notes, due 2015 (US$250 million) (f)	306	247
Notes, due 2017 (US$250 million) (g)	306	247
Notes, due 2028 (US$200 million) (h)	245	198
Notes, due 2032 (US$500 million) (i)	612	494
Notes, due 2035 (US$790 million) (j)	968	781
Notes, due 2037 (US$1,250 million) (k)	1,531	1,235
Subordinated Debentures, due 2043 (US$460 million) (l)	563	454
	6,652	**4,688**
Unamortized Debt Issue Costs	(74)	(78)
Total	**6,578**	**4,610**

(a) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes with interest payable semi-annually at a rate of 6.3%. The principal of $125 million was repaid in full in June 2008.

(b) Canexus term credit facilities

Canexus has $420 million (US$343 million) of committed, secured term credit facilities, available until 2011. At December 31, 2008, $223 million (US$182 million) was drawn on these facilities (2007—$202 million (US$204 million)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus' assets. The credit facility also contains covenants with respect to certain financial ratios for Canexus. During 2008, the weighted-average interest rate on the Canexus term credit facilities was 4.4% (2007—6.1%).

(c) Term credit facilities

We have unsecured term credit facilities of $3.7 billion (US$3.1 billion), available until 2012. At December 31, 2008, $1.2 billion (US$1 billion) was drawn on these facilities (2007—$211 million (US$214 million)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2008, the weighted-average interest rate was 2.8% (2007—5.8%). At December 31, 2008, $381 million (US$311 million) of these facilities were utilized to support outstanding letters of credit (December 31, 2007—$283 million (US$286 million)).

(d) Canexus Notes, due 2013

During the second quarter of 2008, Canexus issued US$50 million of notes. Interest is payable quarterly at a rate of 6.57% and the principal is to be repaid in May 2013. Canexus may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(e) Notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05%, and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(f) Notes, due 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2%, and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(g) Notes, due 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65%, and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(h) Notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4%, and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(i) Notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875%, and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(j) Notes, due 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875%, and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(k) Notes, due 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4%, and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(l) Subordinated debentures, due 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(m) Long-term debt repayments

2009	–
2010	–
2011	223 [1]
2012	1,225
2013	673
Thereafter	4,531
Total	**6,652**

1 *Canexus term credit facility.*

(n) Debt covenants

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2008 and 2007, we were in compliance with all covenants.

(o) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $613 million (US$501 million), none of which were drawn at December 31, 2008 (2007—$nil). We utilized $29 million (US$24 million) of these facilities to support outstanding letters of credit at December 31, 2008 (2007—$196 million (US$198 million)). Interest is payable at floating rates. During 2008, the weighted-average interest rate on our short-term borrowings was 3.2% (2007—5.8%).

(p) Interest expense

	2008	2007	2006
Long-Term Debt	315	323	275
Other	19	18	19
Total	334	341	294
Less: Capitalized	(240)	(173)	(241)
Total	**94**	**168**	**53**

Capitalized interest relates to and is included as part of the cost of oil and gas and Syncrude properties. The capitalization rates are based on our weighted-average cost of borrowings.

11. CAPITAL DISCLOSURE

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects which require significant capital investment prior to cash flow generation and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term borrowings, long-term debt and shareholders' equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of shareholders' equity, short-term borrowings, long-term debt, and cash and cash equivalents as follows:

Net Debt [1]	2008	2007
Long-Term Debt	6,578	4,610
Less: Cash and Cash Equivalents	(2,003)	(206)
Total	**4,575**	**4,404**
Shareholders' Equity	**7,139**	**5,610**

1 Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities and interest coverage ratios at various commodity prices.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure that does not have any standard meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the twelve months ended December 31, 2008, our net debt to cash flow from operating activities ratio was 1.1 times compared to 1.6 times at December 31, 2007. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio allows us to monitor our ability to fund the interest requirements associated with our debt. Our interest coverage strengthened in 2008 from 12.1 times at the end of 2007 to 15.6 times at December 31, 2008.

Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, DD&A (EBITDA) by interest expense before capitalized interest. EBITDA is a non-GAAP measure which is calculated using net income excluding interest expense, provision for income taxes, exploration expenses, DD&A, impairment and other non-cash expenses. The calculation of EBITDA is set out in the following table.

	2008	2007
Net Income	1,715	1,086
Add:		
Interest Expense	94	168
Provision for Income Taxes	1,457	792
Depreciation, Depletion, Amortization and Impairment	2,014	1,767
Exploration Expense	402	326
Recovery of Non-Cash Stock-Based Compensation	(272)	(109)
Change in Fair Value of Crude Oil Put Options	(203)	43
Other Non-Cash Expenses	(1)	14
EBITDA	**5,206**	**4,087**

12. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2008	2007
Asset Retirement Obligations, Beginning of Year	832	704
Obligations Incurred with Development Activities	32	105
Obligations Settled	(45)	(23)
Accretion Expense	58	44
Revisions to Estimates	159	79
Effects of Changes in Foreign Exchange Rate	23	(77)
End of Year [1, 2]	**1,059**	**832**

1 Obligations due within twelve months of $35 million (2007—$40 million) have been included in accounts payable and accrued liabilities.
2 Obligations relating to our oil and gas activities amount to $1,009 million (2007—$786 million) and obligations relating to our chemicals business amount to $50 million (2007—$46 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,393 million (2007—$2,165 million). We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 5.9% (2007—5.9%). Approximately $409 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

13. DEFERRED CREDITS AND OTHER LIABILITIES

	2008	2007
Deferred Tax Credit	709	–
Long-Term Marketing Derivative Contracts (Note 7a)	294	163
Deferred Transportation Revenue	69	82
Fixed-Price Natural Gas Contracts and Swaps (Note 7b)	26	51
Defined Benefit Pension Obligations (Note 14)	67	57
Capital Lease Obligations	53	52
Other	106	54
Total	**1,324**	**459**

During the third quarter of 2008, we completed an internal reorganization and financing of our assets in the North Sea which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. Accordingly, we have deferred recognizing $709 million of tax deductions in our consolidated income statement.

14. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen and Canexus have contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

(a) Defined benefit pension plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2008			2007		
	Nexen	**Canexus**	**Syncrude**	**Nexen**	**Canexus**	**Syncrude**
Change in Projected Benefit Obligation (PBO)						
Beginning of Year	272	62	125	252	58	116
Service Cost	23	4	4	18	3	5
Interest Cost	17	4	7	13	3	6
Plan Participants' Contributions	5	1	1	4	1	1
Actuarial Loss/(Gain)	(39)	(11)	(25)	(2)	(3)	1
Benefits Paid	(13)	(1)	(5)	(13)	–	(4)
End of Year [1]	**265**	**59**	**107**	**272**	**62**	**125**
Change in Fair Value of Plan Assets						
Beginning of Year	200	55	74	185	50	69
Actual Return on Plan Assets	(54)	(9)	(19)	18	1	2
Employer's Contribution	15	4	6	6	3	6
Plan Participants' Contributions	5	1	1	4	1	1
Benefits Paid	(13)	(1)	(5)	(13)	–	(4)
End of Year	**153**	**50**	**57**	**200**	**55**	**74**
Reconciliation of Funded Status						
Funded Status [2]	(112)	(9)	(50)	(72)	(7)	(51)
Unamortized Transitional Obligation	–	–	–	–	–	–
Unamortized Prior Service Costs	1	–	–	2	–	–
Unamortized Net Actuarial Loss	60	8	35	31	6	36
Pension Liability	**(51)**	**(1)**	**(15)**	**(39)**	**(1)**	**(15)**
Pension Liability						
Deferred Charges and Other Assets	2	–	–	4	–	–
Accounts Payable and Accrued Liabilities	(2)	–	–	(2)	–	–
Other Deferred Credits and Liabilities (Note 13)	(51)	(1)	(15)	(41)	(1)	(15)
Pension Liability	**(51)**	**(1)**	**(15)**	**(39)**	**(1)**	**(15)**
Assumptions (%)						
Accrued Benefit Obligation at December 31						
Discount Rate	6.50	6.50	6.50	5.25	5.25	5.25
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	5.00
Benefit Cost for Year Ended December 31 [3]						
Discount Rate	5.25	5.25	6.50	5.00	5.00	5.25
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	5.00
Long-Term Annual Rate of Return on Plan Assets [4]	7.00	6.50	8.50	7.00	6.50	8.50

1 *The accumulated benefit obligations (the projected benefit obligation (PBO) excluding future salary increases) of the Nexen and Canexus plans were $179 million and $46 million at December 31, 2008, respectively (2007—$182 million and $47 million, respectively). Nexen's supplemental pension plan's accumulated benefit obligation was $49 million at December 31, 2008 (2007—$48 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $82 million at December 31, 2008 (2007—$92 million).*

2 *Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2008, the PBO for Nexen's supplemental benefits was $62 million (2007—$62 million) and $1 million for Canexus (2007—$1 million). The unfunded obligations for supplemental benefits are backed by irrevocable letters of credit. Subsequent to December 31, 2008, we contributed $46 million to Nexen's defined benefit pension plan to fund existing solvency deficiencies.*

3 *The measurement date is December 31, 2008.*

4 *The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.*

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2008	2007	2006
Nexen			
Cost of Benefits Earned by Employees	23	18	16
Interest Cost on Benefits Earned	17	13	12
Actual (Return) Loss on Plan Assets	54	(18)	(23)
Actuarial (Gains)/Losses	(39)	(2)	9
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	55	11	14
Difference Between Actual and Expected Return on Plan Assets	(71)	5	12
Difference Between Actual and Recognized Actuarial Losses	41	3	(7)
Difference Between Actual and Recognized Past Service Costs	1	1	1
Net Pension Expense	**26**	**20**	**20**
Canexus			
Cost of Benefits Earned by Employees	4	3	3
Interest Cost on Benefits Earned	4	3	3
Actual (Return) Loss on Plan Assets	9	(2)	(6)
Actuarial (Gains)/Losses	(11)	(3)	2
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	6	1	2
Difference Between Actual and Expected Return on Plan Assets	(13)	(1)	3
Difference Between Actual and Recognized Actuarial Gains	11	3	(2)
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**4**	**3**	**3**
Syncrude [1]			
Cost of Benefits Earned by Employees	4	5	5
Interest Cost on Benefits Earned	7	6	5
Actual (Return) Loss on Plan Assets	19	(2)	(8)
Actuarial (Gains)/Losses	(25)	1	–
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	5	10	2
Difference Between Actual and Expected Return on Plan Assets	(26)	(4)	3
Difference Between Actual and Recognized Actuarial Losses	27	1	2
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**6**	**7**	**7**
Total Net Pension Expense	**36**	**30**	**30**

1 *Nexen's share of Syncrude's plan.*

(b) Plan asset allocation at December 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committees of Nexen and Canexus. Nexen's and Canexus' investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's and Canexus' investment policies.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

(%)	Expected 2009	2008	2007
Nexen			
Equity Securities	65	55	64
Debt Securities	35	45	36
Total	**100**	**100**	**100**
Canexus			
Equity Securities	50	50	50
Debt Securities	50	50	50
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	70	68	68
Debt Securities	30	32	32
Total	**100**	**100**	**100**

(c) Defined contribution pension plans

Under these plans, pension benefits are based on plan contributions. During 2008, Canadian pension expense for these plans was $7 million (2007—$6 million; 2006—$4 million). During 2008, US pension expense for these plans was $4 million (2007—$4 million; 2006—$4 million) and UK pension expense for these plans was $6 million (2007—$5 million; 2006—$4 million).

(d) Post-retirement benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. The present value of Nexen employees' future post retirement benefits at December 31, 2008 was $15 million (2007—$10 million) and $2 million for Canexus (2007—$1 million).

(e) Employer funding contributions and benefit payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Our funding contributions for the defined benefit plans are:

	Expected 2009	2008	2007
Nexen [1]	58	15	6
Canexus	3	4	3
Syncrude	7	7	6
Total Defined Benefit Contributions	**68**	**26**	**15**

1 Nexen's defined benefit plan has a solvency deficiency of $46 million at December 31, 2008 and we funded this amount in February 2009.

Our most recent funding valuation was prepared as of June 30, 2008. Our next funding valuation is required by June 30, 2011. Canexus' most recent funding valuation was prepared as of December 31, 2007, and their next funding valuation is required by December 31, 2010. Syncrude's most recent funding valuation was prepared as of December 31, 2006, and their next funding valuation is December 31, 2009.

Our total benefit payments in 2008 were $13 million for Nexen (2007—$13 million). Our share of Syncrude's total benefit payments in 2008 was $5 million (2007—$4 million). Our estimated future payments are as follows:

	Defined Benefit			Other		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
2009	10	1	4	2	–	–
2010	11	1	4	2	–	–
2011	12	2	5	3	–	–
2012	13	2	5	3	–	–
2013	14	3	6	4	–	–
2014–2018	88	20	36	27	–	2

15. SHAREHOLDERS' EQUITY

(a) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(b) Issued common shares and dividends

(thousands of shares)	2008	2007	2006
Issued Common Shares, Beginning of Year	528,305	525,026	522,281
Issue of Common Shares for Cash			
Exercise of Tandem Options	1,911	2,257	1,693
Dividend Reinvestment Plan	871	523	552
Employee Flow-through Shares	499	499	500
Repurchased under Normal Course Issuer Bid	(12,137)	–	–
End of Year	**519,449**	**528,305**	**525,026**
Dividends Declared per Common Share ($/share)	**0.18**	**0.10**	**0.10**
Cash Consideration (Cdn$ millions)			
Exercise of Tandem Options	23	24	16
Dividend Reinvestment Plan	25	16	16
Employee Flow-through Shares	16	16	16
Total	**64**	**56**	**48**

During the year, 871,254 common shares were issued under the Dividend Reinvestment Plan leaving a balance of 3,603,841 common shares (2007—4,475,095; 2006—997,662) reserved for issuance at December 31, 2008. Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

During the year, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid to repurchase up to a maximum of 52,914,046 common shares between August 6, 2008 and August 5, 2009. Under this authorization, we repurchased and cancelled 12,136,900 common shares acquired on the open market through the TSX at an average price of $27.85 per common share, totalling $338 million. Of the amount paid, $22 million reduced the book value of our common shares and the excess of $316 million reduced retained earnings.

The following summarizes the purchase of equity securities in 2008.

Period	(a) Total number of shares purchased (thousands)	(b) Average price paid per share ($/Share)	(c) Total number of shares purchased as part of publicly announced plans or programs (thousands)	(d) Maximum number of shares that may yet to be purchased under the plans or programs (thousands)
August 6–31, 2008	6,200	$31.78	6,200	46,714
September 1–30, 2008	3,787	$27.22	3,787	42,927
October 1–31, 2008	1,094	$16.44	1,094	41,833
November 1–30, 2008	1,056	$18.92	1,056	40,777
December 1–31, 2008	–	–	–	40,777
Total	**12,137**	**$27.85**	**12,137**	

(c) Tandem options

We have granted tandem options to purchase common shares to directors, officers and employees. Each option permits the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price.

	2008		2007		2006	
(thousands of shares)	**Options** (thousands)	**Weighted Average Exercise Price** ($/option)	**Options** (thousands)	**Weighted Average Exercise Price** ($/option)	**Options** (thousands)	**Weighted Average Exercise Price** ($/option)
Outstanding Options, Beginning of Year	27,403	20	30,485	17	30,629	14
Granted	3,534	19	4,007	28	4,802	32
Exercised for Stock	(1,911)	13	(2,257)	10	(1,693)	9
Surrendered for Cash	(3,839)	13	(4,414)	11	(3,043)	9
Cancelled	(552)	30	(418)	22	(210)	19
Expired	(13)	11	–	–	–	–
End of Year	**24,622**	**22**	**27,403**	**20**	**30,485**	**17**
Options Exercisable at End of Year	17,087	21	18,216	16	18,691	12
Common Shares Reserved for Issuance Under the Tandem Option Plan	27,429		29,430		32,470	

The range of exercise prices of options outstanding and exercisable at December 31, 2008 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	**Weighted Average Exercise Price** ($/option)	**Weighted Average Years to Expiry** (years)	**Number of Options** (thousands)	**Weighted Average Exercise Price** ($/option)
$5.00 to $9.99	3,178	8	2	3,178	8
$10.00 to $14.99	4,429	13	1	4,429	13
$15.00 to $19.99	3,523	19	5	12	17
$20.00 to $24.99	10	23	2	10	23
$25.00 to $29.99	8,777	28	3	6,456	28
$30.00 to $34.99	4,640	32	3	2,982	32
$35.00 to $39.99	59	36	3	20	37
$40.00 to $44.99	6	40	4	–	–
Total	**24,622**			**17,087**	

(d) Stock appreciation rights

Our StARs plan entitles employees to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The following stock appreciation rights have been granted:

(thousands of shares)	2008 StARs (thousands)	2008 Weighted Average Exercise Price ($/StAR)	2007 StARs (thousands)	2007 Weighted Average Exercise Price ($/StAR)	2006 StARs (thousands)	2006 Weighted Average Exercise Price ($/StAR)
Outstanding StARs, Beginning of Year	15,435	24	13,890	21	11,928	15
Granted	4,917	19	4,195	29	4,509	32
Exercised for Cash	(2,837)	15	(2,349)	12	(2,165)	10
Cancelled	(529)	31	(301)	26	(382)	19
Expired	–	–	–	–	–	–
End of Year	**16,986**	**25**	**15,435**	**24**	**13,890**	**21**
StARs Exercisable at End of Year	8,119	25	7,525	19	6,151	13

The range of exercise prices of StARs outstanding and exercisable at December 31, 2008 is as follows:

	Outstanding StARs Number of StARs (thousands)	Outstanding StARs Weighted Average Exercise Price ($/StAR)	Outstanding StARs Weighted Average Years to Expiry (years)	Exercisable StARs Number of StARs (thousands)	Exercisable StARs Weighted Average Exercise Price ($/StAR)
$5.00 to $9.99	138	8	2	138	8
$10.00 to $14.99	1,978	13	1	1,978	13
$15.00 to $19.99	4,866	19	5	33	17
$20.00 to $24.99	70	23	2	63	23
$25.00 to $29.99	5,340	28	3	3,149	28
$30.00 to $34.99	4,489	32	3	2,740	32
$35.00 to $39.99	77	37	4	18	37
$40.00 to $44.99	19	44	4	–	–
$45.00 to $49.99	9	47	4	–	–
Total	**16,986**			**8,119**	

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases and transportation, storage and drilling rig commitments as at December 31, 2008 comprise of the following:

	2009	2010	2011	2012	2013	Thereafter
Operating Leases	91	115	109	105	100	195
Transportation and Storage Commitments	379	235	176	150	117	204
Drilling Rig Commitments	408	442	455	329	130	10

We have a number of lawsuits and claims pending including income tax reassessments (see Note 18), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2008, total rental expense under operating leases was $59 million (2007—$53 million; 2006—$49 million).

From time to time, we enter into certain types of contracts that require us to indemnify parties against possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary, and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities, would not have a material adverse effect on our liquidity, financial condition or results of operations.

17. MARKETING AND OTHER INCOME

	2008	2007	2006
Marketing Revenue, Net	467	959	1,309
Business Interruption Insurance Proceeds [1]	–	–	154
Change in Fair Value of Crude Oil Put Options	203	(43)	(11)
Interest	28	39	36
Foreign Exchange Gains (Losses)	128	(22)	(72)
Gains on Disposition of Assets	3	2	4
Other	(16)	86	30
Total	**813**	**1,021**	**1,450**

1 In 2006, we received business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005 and by generator failures in our UK operations in 2005.

18. INCOME TAXES

(a) Temporary differences

	2008		2007	
	Future Income Tax Assets	**Future Income Tax Liabilities**	**Future Income Tax Assets [1]**	**Future Income Tax Liabilities**
Property, Plant and Equipment, Net	27	2,543	25	2,229
Tax Losses Carried Forward	300	–	256	–
Deferred Income	–	76	–	61
Recoverable Taxes	24	–	5	–
Total	**351**	**2,619**	**286**	**2,290**

1 In 2007, future income tax assets of $18 million that we expected to realize in the following twelve months were included in other current assets.

(b) Canadian and foreign income taxes

	2008	2007	2006
Income (Loss) before Income Taxes			
Canadian	(100)	(33)	(352)
Foreign	3,268	1,929	1,648
	3,168	1,896	1,296
Provision for Income Taxes			
Current			
Canadian	1	1	14
Foreign	858	433	354
	859	434	368
Future			
Canadian	22	12	(96)
Foreign	576	346	411
	598	358	315
Total	**1,457**	**792**	**683**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, Colombia, the UK, the US and Norway.

(c) Reconciliation of effective tax rate to the Canadian statutory tax rate

	2008	2007	2006
Income before Provision for Income Taxes	3,168	1,896	1,296
Provision for Income Taxes Computed at the Canadian Statutory Rate	893	537	401
Add (Deduct) the Tax Effect of:			
Royalties, Rentals and Similar Payments to Provincial Governments	–	–	15
Resource Allowance and Provincial Tax Rebates	–	–	(15)
Foreign Tax Rate Differential	525	233	(9)
Additional Canadian Tax on Canadian Resource Income	–	–	10
Higher (Lower) Tax Rates on Capital Gains	9	(5)	(3)
Federal and Provincial Capital Tax	2	1	13
Effect of Changes in Tax Rates	–	(15)	245
Non-Deductible Expenses and Other	28	41	26
Provision for Income Taxes	**1,457**	**792**	**683**
Effective Tax Rate	**46%**	**42%**	**53%**

During the first quarter of 2006, we recorded a future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom. The United Kingdom parliament increased the supplemental tax rate from 10% to 20%, effective January 1, 2006.

In 2007 and 2006, the federal government and some provincial governments in Canada reduced statutory corporate income tax rates. This reduced our liability and provision for future income taxes by $15 million in 2007 and $32 million in 2006.

(d) Available unused tax losses and tax contingencies

At December 31, 2008, we had unused tax losses totalling $954 million (2007—$820 million; 2006—$1,258 million). The majority of these losses are in Canada and the US and will expire between 2016 and 2028.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an appropriate provision for income taxes based on available information.

19. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2008	2007	2006
Weighted-Average Number of Common Shares, Basic	526.1	527.1	524.2
Shares Issuable Pursuant to Tandem Options	18.8	26.6	27.7
Shares to be Notionally Purchased from Proceeds of Tandem Options	(12.7)	(15.7)	(14.0)
Weighted-Average Number of Common Shares, Diluted	**532.2**	**538.0**	**537.9**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2008, we excluded 5,694,055 tandem options (2007—49,333; 2006—422,566), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

20. CASH FLOWS

(a) Charges and credits to income not involving cash

	2008	2007	2006
Depreciation, Depletion, Amortization and Impairment	2,014	1,767	1,124
Stock-Based Compensation	(272)	(109)	101
Gains on Disposition of Assets	(3)	(2)	(4)
Provision for Future Income Taxes	598	358	315
Change in Fair Value of Crude Oil Put Options	(203)	43	11
Net (Loss) Income Attributable to Non-Controlling Interests	(4)	18	12
Other	6	(2)	70
Total	**2,136**	**2,073**	**1,629**

(b) Changes in non-cash working capital

	2008	2007	2006
Accounts Receivable	950	(797)	345
Inventories and Supplies	246	(97)	(302)
Other Current Assets	5	(15)	(14)
Accounts Payable and Accrued Liabilities	(1,232)	691	(72)
Other	26	–	–
Total	**(5)**	**(218)**	**(43)**
Relating to:			
Operating Activities	119	(348)	(177)
Investing Activities	(124)	130	134
Total	**(5)**	**(218)**	**(43)**

(c) Other cash flow information

	2008	2007	2006
Interest Paid	319	328	278
Income Taxes Paid	1,055	408	398

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $137 million (2007—$123 million; 2006—$128 million).

21. SUBSEQUENT EVENT

In January 2009, we completed the acquisition of an additional 15% interest in the Long Lake Project and the joint venture lands for $735 million.

22. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, offshore West Africa and Norway.

Energy Marketing: Our energy marketing group sells our crude oil and natural gas, markets third-party crude oil, natural gas, NGLs and power (including electricity generation) and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the Athabasca oil sands in northern Alberta.

Chemicals: Through our investment in Canexus, we manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. We produce sodium chlorate at four facilities in Canada and one in Brazil. We produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses with the exception of Chemicals. Identifiable assets are those used in the operations of the segments.

2008 Operating and Geographic Segments

	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
(Cdn$ millions)	Yemen	Canada	US	UK	Other Countries[1]					
Net Sales[2]	1,093	656	665	3,580	192	70	691	477[3]	–	7,424
Marketing and Other	12	3	4	5	–	467	6	(50)	366[4]	813
	1,105	659	669	3,585	192	537	697	427	366	8,237
Less: Expenses										
Operating	176	182	94	253	10	43	280	297	–	1,335
Depreciation, Depletion, Amortization and Impairments[5]	160	208	475	999	17	19	49	44	43	2,014
Transportation and Other	9	12	3	19	–	805	16	55	48	967
General and Administrative[6]	(7)	20	38	(8)	13	79	1	33	88	257
Exploration	5	79	109	86	123[7]	–	–	–	–	402
Interest	–	–	–	–	–	–	–	12	82	94
Income (Loss) before Income Taxes	762	158	(50)	2,236	29	(409)	351	(14)	105	3,168
Less: Provision for (Recovery of) Income Taxes[8]	264	45	(19)	1,126	(4)	(102)	99	2	46	1,457
Net Income (Loss)	498	113	(31)	1,110	33	(307)	252	(16)	59	1,711
Non-Controlling Interests	–	–	–	–	–	–	–	(4)	–	(4)
Net Income (Loss)	**498**	**113**	**(31)**	**1,110**	**33**	**(307)**	**252**	**(12)**	**59**	**1,715**
Identifiable Assets	**342**	**6,643[9]**	**2,044**	**6,632**	**701**	**3,280[10]**	**1,198**	**573**	**742**	**22,155**
Capital Expenditures										
Development and Other	92	1,180	251	545	190	8	55	88	53	2,462
Exploration	9	225	154	146	48	–	–	–	–	582
Proved Property Acquisitions	–	22	–	–	–	–	–	–	–	22
Total	**101**	**1,427**	**405**	**691**	**238**	**8**	**55**	**88**	**53**	**3,066**
PP&E										
Cost	2,808	8,134	4,398	6,532	554	246	1,372	940	331	25,315
Less: Accumulated DD&A	2,610	1,786	2,702	2,159	113	76	236	507	204	10,393
Net Book Value[2]	**198**	**6,348[9]**	**1,696**	**4,373**	**441**	**170**	**1,136**	**433**	**127**	**14,922**
Goodwill	**–**	**–**	**–**	**341**	**–**	**49**	**–**	**–**	**–**	**390**

1 *Includes results of operations from producing activities in Colombia.*

2 *Net sales made from all segments originating in Canada: 1,570*
PP&E located in Canada: 8,121

3 *Net sales for our chemicals operations include:*

Canada	*153*
US	*214*
Brazil	*110*
Total	***477***

4 *Includes interest income of $28 million, foreign exchange gains of $128 million, increase in the fair value of crude oil put options of $203 million and other income of $7 million.*

5 *Includes an impairment charge related to oil and gas properties in the UK North Sea and the US Gulf of Mexico of $318 million and $250 million, respectively.*

6 *Includes recovery of stock-based compensation expense of $160 million.*

7 *Includes exploration activities primarily in Norway and Colombia.*

8 *The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.*

9 *Includes costs of $4,742 million related to our insitu oil sands (Long Lake and future phases).*

10 *79% of Marketing's identifiable assets are accounts receivable and inventories.*

2007 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: Yemen	Oil and Gas: Canada	Oil and Gas: US	Oil and Gas: UK	Oil and Gas: Other Countries[1]	Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
Net Sales[2]	1,086	441	616	2,285	148	48	545	414[3]	–	5,583
Marketing and Other	10	6	–	39	–	959	–	33	(26)[4]	1,021
	1,096	447	616	2,324	148	1,007	545	447	(26)	6,604
Less: Expenses										
Operating	171	173	102	212	8	34	208	257	–	1,165
Depreciation, Depletion, Amortization and Impairment	213	166	641[5]	599	8	13	53	45	29	1,767
Transportation and Other	8	22	–	–	–	806	17	39	16	908
General and Administrative[6]	(6)	50	38	3	40	87	1	31	130	374
Exploration	5	27	134	69	91[7]	–	–	–	–	326
Interest	–	–	–	–	–	–	–	11	157	168
Income (Loss) before Income Taxes	705	9	(299)	1,441	1	67	266	64	(358)	1,896
Less: Provision for (Recovery of) Income Taxes[8]	248	3	(103)	712	–	21	75	18	(182)	792
Net Income (Loss)	457	6	(196)	729	1	46	191	46	(176)	1,104
Non-Controlling Interests	–	–	–	–	–	–	–	18	–	18
Net Income (Loss)	**457**	**6**	**(196)**	**729**	**1**	**46**	**191**	**28**	**(176)**	**1,086**
Identifiable Assets	**359**	**5,379[9]**	**1,640**	**4,642**	**317**	**3,663[10]**	**1,212**	**487**	**376**	**18,075**
Capital Expenditures										
Development and Other	124	1,381	414	551	53	4	36	62	52	2,677
Exploration	12	123	275	119	44	–	–	–	–	573
Proved Property Acquisitions	–	1	104[11]	46[12]	–	–	–	–	–	151
Total	**136**	**1,505**	**793**	**716**	**97**	**4**	**36**	**62**	**52**	**3,401**
PP&E										
Cost	2,178	6,736	3,069	4,723	263	246	1,332	831	315	19,693
Less: Accumulated DD&A	1,950	1,597	1,765	908	77	62	205	463	168	7,195
Net Book Value[2]	**228**	**5,139[9]**	**1,304**	**3,815**	**186**	**184**	**1,127**	**368**	**147**	**12,498**
Goodwill	**–**	**–**	**–**	**276**	**–**	**50**	**–**	**–**	**–**	**326**

1 Includes results of operations from producing activities in Colombia.
2 Net sales made from all segments originating in Canada: 1,188
PP&E located in Canada: 6,893
3 Net sales for our chemicals operations include:

Canada	*154*
US	*169*
Brazil	*91*
Total	***414***

4 Includes interest income of $39 million, foreign exchange losses of $22 million and decrease in the fair value of crude oil put options of $43 million.
5 Includes an impairment charge of $366 million related to oil and gas properties in the Gulf of Mexico.
6 Includes stock-based compensation expense of $38 million.
7 Includes exploration activities primarily in Nigeria, Norway and Colombia.
8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
9 Includes costs of $3,695 million related to our insitu oil sands (Long Lake and future phases).
10 84% of Marketing's identifiable assets are accounts receivable and inventories.
11 Includes acquisition of producing properties in the Gulf of Mexico.
12 Includes acquisition of additional interests in the Scott and Telford fields.

2006 Operating and Geographic Segments

	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
(Cdn$ millions)	**Yemen**	**Canada**	**US**	**UK**	**Other Countries**[1]					
Net Sales[2]	1,328	459	629	477	139	51	446	407[3]	–	3,936
Marketing and Other	8	7	81[4]	85[5]	1	1,309	–	6	(47)[6]	1,450
	1,336	466	710	562	140	1,360	446	413	(47)	5,386
Less: Expenses										
Operating	151	143	106	80	8	31	187	249	–	955
Depreciation, Depletion, Amortization and Impairment[7]	327	162	296	216	10	12	33	40	28	1,124
Transportation and Other	6	33	–	–	1	789	18	40	154[8]	1,041
General and Administrative[9]	17	80	58	14	44	112	1	29	200	555
Exploration	4	26	214	46	72[10]	–	–	–	–	362
Interest	–	–	–	–	–	–	–	11	42	53
Income (Loss) before Income Taxes	831	22	36	206	5	416	207	44	(471)	1,296
Less: Provision for (Recovery of) Income Taxes[11]	289	7	13	378[12]	1	151	66	15	(237)	683
Net Income (Loss)	542	15	23	(172)	4	265	141	29	(234)	613
Non-Controlling Interests	–	–	–	–	–	–	–	12	–	12
Net Income (Loss)	**542**	**15**	**23**	**(172)**	**4**	**265**	**141**	**17**	**(234)**	**601**
Identifiable Assets	**464**	**3,923**[13]	**1,620**	**5,490**	**245**	**3,528**[14]	**1,186**	**459**	**241**	**17,156**
Capital Expenditures										
Development and Other	145	1,434	418	596	28	47	86	27	45	2,826
Exploration	37	163	177	62	52	–	–	–	–	491
Proved Property Acquisitions	–	12	–	1	–	–	–	–	–	13
Total	**182**	**1,609**	**595**	**659**	**80**	**47**	**86**	**27**	**45**	**3,330**
PP&E										
Cost	2,404	5,216	2,889	4,710	249	226	1,304	854	286	18,138
Less: Accumulated DD&A	2,128	1,448	1,445	432	78	47	179	494	148	6,399
Net Book Value[2]	**276**	**3,768**[13]	**1,444**	**4,278**	**171**	**179**	**1,125**	**360**	**138**	**11,739**
Goodwill	**–**	**–**	**–**	**325**	**–**	**52**	**–**	**–**	**–**	**377**

1 Includes results of operations from producing activities in Colombia.
2 Net sales made from all segments originating in Canada: 1,095
PP&E located in Canada: 5,483
3 Net sales for our chemicals operations include:

Canada	*139*
US	*185*
Brazil	*83*
Total	***407***

4 Includes $80 million of business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005.
5 Includes $74 million of business interruption insurance proceeds for generator failures in 2005.
6 Includes interest income of $36 million, foreign exchange losses of $72 million and decrease in the fair value of crude oil put options of $11 million.
7 Includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.
8 Includes $151 million (US$135 million) accrual with respect to the Block 51 arbitration settlement.
9 Includes stock-based compensation expense of $210 million.
10 Includes exploration activities primarily in Nigeria, Norway and Colombia.
11 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
12 Includes future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom (see Note 18).
13 Includes costs of $2,444 million related to our insitu oil sands (Long Lake and future phases).
14 80% of Marketing's identifiable assets are accounts receivable and inventories.

23. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP
For the Three Years ended December 31, 2008

(Cdn$ millions, except per share amounts)	2008	2007	2006
Revenues and Other Income			
Net Sales	7,424	5,583	3,936
Marketing and Other (i); (vi); (vii)	796	938	1,459
	8,220	6,521	5,395
Expenses			
Operating (ii)	1,335	1,167	958
Depreciation, Depletion, Amortization and Impairment	2,014	1,767	1,124
Transportation and Other (vi)	964	906	1,037
General and Administrative (v)	263	401	597
Exploration	402	326	362
Interest	94	168	53
	5,072	4,735	4,131
Income before Provision for Income Taxes	3,148	1,786	1,264
Provision for Income Taxes			
Current	859	434	368
Deferred (i); (ii); (v); (vii)	589	322	305
	1,448	756	673
Net Income before Non-Controlling Interests	1,700	1,030	591
Net Income (Loss) Attributable to Non-Controlling Interests	(4)	18	12
Net Income—US GAAP [1]	**1,704**	**1,012**	**579**
Earnings Per Common Share ($/share) (Note 19)			
Basic	3.24	1.92	1.10
Diluted	3.20	1.88	1.08

1 *Reconciliation of Canadian and US GAAP Net Income*

(Cdn$ millions)	*2008*	*2007*	*2006*
Net Income—Canadian GAAP	*1,715*	*1,086*	*601*
Impact of US Principles, Net of Income Taxes:			
Ineffective Portion of Cash Flow Hedges (i)	–	*(2)*	*9*
Pre-operating Costs (ii)	–	*(1)*	*(2)*
Stock-based Compensation (v)	*(4)*	*(19)*	*(29)*
Inventory Valuation (vii)	*(7)*	*(52)*	–
Net Income—US GAAP	***1,704***	***1,012***	***579***

Consolidated Balance Sheet—US GAAP
December 31, 2008 and 2007

(Cdn$ millions, except share amounts)	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	2,003	206
Restricted Cash	103	203
Accounts Receivable	3,163	3,502
Inventories and Supplies (vii)	426	615
Other	169	89
Total Current Assets	5,864	4,615
Property, Plant and Equipment Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,786 (December 31, 2007—$7,588) (ii); (iv)	14,873	12,449
Goodwill	390	326
Deferred Income Tax Assets	351	268
Deferred Charges and Other Assets	570	324
TOTAL ASSETS	**22,048**	**17,982**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable and Accrued Liabilities (v)	3,384	4,233
Accrued Interest Payable	67	54
Dividends Payable	26	13
Total Current Liabilities	3,477	4,300
Long-Term Debt	6,578	4,610
Deferred Income Tax Liabilities (ii); (iii); (v); (vii); (viii)	2,543	2,230
Asset Retirement Obligations	1,024	792
Deferred Credits and Other Liabilities (iii)	1,428	534
Non-Controlling Interests	52	67
Shareholders' Equity		
Common Shares, no par value Authorized: Unlimited Outstanding: 2008—519,448,590 shares 2007—528,304,813 shares	981	917
Contributed Surplus	2	3
Retained Earnings (i)–(v); (vii); (viii)	6,172	4,876
Accumulated Other Comprehensive Loss (i); (iii)	(209)	(347)
Total Shareholders' Equity	6,946	5,449
Commitments, Contingencies and Guarantees (Notes 16 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**22,048**	**17,982**

Consolidated Statement of Comprehensive Income—US GAAP
For the Three Years ended December 31, 2008

(Cdn$ millions)	2008	2007	2006
Net Income—US GAAP	1,704	1,012	579
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment	159	(132)	–
Change in Mark to Market on Cash Flow Hedges (i)	–	(61)	77
Minimum Unfunded Pension Liability (iii)	–	–	5
Unamortized Defined Benefit Pension Plan Costs (iii)	(21)	2	–
Comprehensive Income	**1,842**	**821**	**661**

Consolidated Statement of Accumulated Other Comprehensive Loss—US GAAP
December 31, 2008 and 2007

(Cdn$ millions)	2008	2007
Foreign Currency Translation Adjustment	(134)	(293)
Unamortized Defined Benefit Pension Plan Costs (iii)	(75)	(54)
Accumulated Other Comprehensive Loss (AOCL)	**(209)**	**(347)**

Notes to the Consolidated US GAAP Financial Statements:

i. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. On January 1, 2007, we adopted the equivalent Canadian standard for derivative instruments and hedging.

Future sale of gas inventory:

We use futures and swaps as cash flow hedges against the commodity price risk on the future sale of our gas inventory. Prior to January 1, 2007, we included the hedging derivative contracts on our US GAAP Consolidated Balance Sheet with the effective portion of gains or losses recognized in AOCI. The ineffective gain or loss was included in marketing and other within the US GAAP net income immediately.

In 2005, we recognized $11 million ($7 million, net of income taxes) of ineffective losses related to these hedges in our US GAAP net income. Under Canadian GAAP, these losses were recognized in 2006.

At December 31, 2006, we included $25 million of gains on these cash flow hedges in accounts receivable. AOCI includes the effective portion of $23 million ($16 million, net of income taxes) and $2 million ($2 million, net of income taxes) of the ineffective portion in our US GAAP net income. Under Canadian GAAP, these gains were recognized in 2007.

ii. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- in 2008, operating expenses do not include any pre-operating costs (2007—$2 million ($1 million, net of income taxes); 2006—$3 million ($2 million, net of income taxes)); and
- PP&E is lower under US GAAP by $30 million (December 31, 2007—lower by $30 million) and deferred income tax liabilities is $11 million lower (December 31, 2007—lower by $11 million).

iii. On December 31, 2006, we adopted FASB Statement No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* for US GAAP. This requires, among other things, the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability. At year end, the unfunded amount of our defined benefit pension plans that was not included in the Pension Liability under Canadian GAAP was $104 million (2007—$75 million). This amount has been included in deferred credits and other liabilities and $75 million, net of income taxes, (2007—$54 million, net of income taxes), has been included in AOCI. Prior to the adoption of FAS 158 on December 31, 2006, we included our minimum unfunded pension liability in our US GAAP Consolidated Balance Sheet.

iv. On January 1, 2003, we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

v. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. In addition, under Canadian principles, we retroactively adopted EIC-162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, US GAAP requires the accelerated recognition of stock-based compensation expense for such employees for awards granted on or after January 1, 2006. As a result:

- general and administrative expense is higher by $6 million ($4 million, net of income taxes) for the year ended December 31, 2008 (2007—higher by $27 million ($19 million, net of income taxes); 2006—higher by $42 million ($29 million, net of income taxes)); and
- accounts payable and accrued liabilities are higher by $58 million at December 31, 2008 (2007—higher by $53 million) and deferred income tax liabilities are $17 million lower (2007—lower by $15 million).

vi. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Gains of $3 million were reclassified from marketing and other to transportation and other (2007—$2 million; 2006—$4 million).

vii. Under Canadian GAAP, we began carrying our commodity inventory held for trading purposes at fair value, less any costs to sell effective October 1, 2007. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result:

- marketing and other is lower by $14 million ($7 million, net of income taxes) for the year ended December 31, 2008 (2007 lower by $79 million, ($52 million net of income tax)); and
- inventories are lower by $58 million at December 31, 2008 (2007—lower by $44 million) and deferred income tax liabilities are $21 million lower (2007—lower by $14 million).

viii. On January 1, 2007, we adopted FASB Interpretation 48 *Accounting for Uncertainty in Income Taxes* (FIN 48) regarding accounting and disclosure for uncertain tax positions. On the adoption of FIN 48, we recorded a cumulative effect of a change in accounting principle of $28 million. This amount increased our deferred income tax liabilities and decreased our retained earnings as at January 1, 2007 in our US GAAP—Consolidated Balance Sheet.

As at December 31, 2008, the total amount of our unrecognized tax benefits was approximately $249 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2008, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP—Consolidated Balance Sheet was approximately $9 million. We had no interest or penalties included in the US GAAP—Consolidated Statement of Income for the year ended December 31, 2008.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2008 the following tax years remained subject to examination, (i) Canada—1985 to date, (ii) United Kingdom—2007 to date and (iii) United States—2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next twelve months.

Reconciliation of Unrecognized Tax Benefits

(Cdn$ millions)	
Balance at January 1, 2008	221
Additions for tax positions related to the current year	9
Additions for tax positions related to prior years	55
Reductions for tax positions related to prior years	(36)
Balance at December 31, 2008	**249**

Stock-Based Compensation

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified prospective approach and graded vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights (StARs) are considered liability-based stock compensation plans. Under the modified prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of $2 million. This amount was recorded in general and administrative expenses in our US GAAP Consolidated Statement of Income in 2006.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans (the intrinsic-value method). Accordingly, obligations were accrued on a graded vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value and remeasured in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans) using the fair-value method.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of our stock-based compensation, with the following assumptions:

Expected Annual Dividends per Common Share ($/share)	0.20
Expected Volatility	52%
Risk-Free Interest Rate	1.0%–1.6%
Weighted-Average Expected Life of Compensation Instruments (years)	2.9–3.2

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the implied volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds. Our valuation methodology and assumptions are consistent with those previously used under FAS 123.

Stock Options

	Number (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/option)
Outstanding at December 31, 2008	24,622	22	2.6	87	6
Outstanding at December 31, 2008 and Expected to Vest	24,388	22	2.6	86	6
Exercisable at December 31, 2008	17,087	21	1.9	80	6

The total intrinsic value of stock options exercised during the year ended December 31, 2008 was $88 million (2007—$149 million; 2006—$109 million). As at December 31, 2008, we had $34 million of unrecognized compensation expense related to stock options which we expect to recognize over a weighted-average period of 1.6 years.

Stock Appreciation Rights

	Number (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2008	16,986	25	3.3	30	5
Outstanding at December 31, 2008 and Expected to Vest	16,558	25	3.3	29	5
Exercisable at December 31, 2008	8,119	25	2.3	19	4

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2008 was $52 million (2007—$50 million; 2006—$46 million). As at December 31, 2008, we had $42 million of unrecognized compensation expense related to stock appreciation rights which we expect to recognize over a weighted-average period of 1.6 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2008, stock-based compensation recovery of $154 million (2007—$65 million expense; 2006—$252 million expense) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2008, cash proceeds of $23 million were received related to the exercise of stock options (2007—$24 million; 2006—$16 million). For the year ended December 31, 2008, $121 million was paid related to the exercise of stock options and stock appreciation rights (2007—$149 million; 2006—$119 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $34 million (2007—$42 million; 2006—$37 million) for the period.

Stock-Based Compensation Expense for Retired and Retirement Eligible Employees

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees on or after January 1, 2006. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated graded vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), our stock-based compensation expense would decrease by $2 million for the year ended December 31, 2008 (2007—$9 million; 2006—$10 million).

Changes in Accounting Policies—US GAAP

Fair Value Measurements

On January 1, 2008, we adopted FASB Statement 157, *Fair Value Measurements* which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The adoption of this statement did not have a material impact on our results of operations or financial position. The additional disclosures required by the statement are included in Note 7.

Pension

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.* This statement also requires measurement of the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. Effective December 31, 2008, we adopted the change in measurement date provision of FASB Statement 158. The funded status of our defined benefit pension plan is now as of the balance sheet date of December 31, 2008. The adoption of this change did not have a material impact on our results of operations or financial position.

New Accounting Pronouncements—US GAAP

In December 2007, FASB issued Statement 141 (revised), *Business Combinations.* Statement 141 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements,* an amendment of ARB No. 51. This statement clarifies that a non-controlling interest in a subsidiary should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities,* an amendment of FASB Statement 133. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged position. The statement also requires the disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, FASB issued FSP FAS 132 (R)-1, *Employers' Disclosures about Post-retirement Benefit Plan Assets* which provides guidance on disclosures about plan assets of a defined benefit pension or other post-retirement plans. This statement is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Net Sales	1,870	1,140	2,071	1,399	2,213	1,446	1,270	1,598
Income (Loss) before Income Taxes is Comprised of:								
Oil and Gas[1]	1,050	303	976	604	1,364	642	(255)	308
Energy Marketing	14	(4)	(183)	70	(79)	(4)	(161)	5
Syncrude	78	54	97	48	139	88	37	76
Chemicals	(4)	11	11	21	5	25	(26)	7
Corporate and Other	(38)	(145)	(208)	(93)	77	(63)	274	(57)
	1,100	**219**	**693**	**650**	**1,506**	**688**	**(131)**	**339**
Net Income (Loss)—Canadian GAAP	**630**	**121**	**380**	**368**	**886**	**403**	**(181)**	**194**
US GAAP Adjustments	(13)	(3)	(62)	(14)	120	(15)	(56)	(42)
Net Income (Loss)—US GAAP	**617**	**118**	**318**	**354**	**1,006**	**388**	**(237)**	**152**
Earnings (Loss) per Common Share ($/share)								
Canadian GAAP—Basic	1.19	0.23	0.72	0.70	1.68	0.77	(0.35)	0.37
Canadian GAAP—Diluted	1.17	0.22	0.70	0.68	1.66	0.75	(0.35)	0.36
US GAAP—Basic	1.17	0.22	0.60	0.67	1.91	0.74	(0.46)	0.29
US GAAP—Diluted	1.15	0.22	0.59	0.66	1.89	0.72	(0.46)	0.28
Dividends Declared[2]	0.025	0.025	0.050	0.025	0.050	0.025	0.050	0.025
Common Share Prices ($/share)								
Toronto Stock Exchange—High	34.20	37.60	43.45	36.51	41.47	36.32	29.10	32.63
Toronto Stock Exchange—Low	26.00	29.66	29.69	31.25	21.12	27.21	13.33	27.88
New York Stock Exchange—High (US$)	34.57	31.88	42.71	32.21	40.99	34.79	23.99	34.37
New York Stock Exchange—Low (US$)	25.11	25.18	28.87	29.08	20.56	25.25	10.81	27.58

1 *The fourth quarter of 2008 includes an impairment charge of $568 million relating to oil and gas properties in the US Gulf of Mexico and the UK North Sea. The fourth quarter of 2007 includes an impairment charge of $366 million relating to oil and gas properties in the Gulf of Mexico.*

2 *In February 2009, the Board of Directors declared a quarterly dividend of $0.05 per common share, payable April 1, 2009, to shareholders of record on March 10, 2009.*

3 *At December 31, 2008, there were 1,624 registered holders of common shares and 519,448,590 common shares outstanding.*

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the FASB Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of crude oil and gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. See Critical Accounting Estimates in Item 7 for a description of our oil and gas and mining reserves estimation process.

	Total		Yemen [1]	Canada			United States		United Kingdom		Other Countries [3]
Conventional oil and bitumen are in mmbbls and natural gas is in bcf	Oil	Gas	Oil	Oil	Gas	Bitumen [2]	Oil	Gas	Oil	Gas	Oil
Proved Developed and Undeveloped Reserves [4]											
December 31, 2005	**304**	**532**	**59**	**50**	**305**	**–**	**41**	**215**	**143**	**12**	**11**
Extensions and Discoveries	52	89	1	1	54	–	2	26	23	9	25
Purchases of Reserves in Place	–	1	–	–	1	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions – Technical	2	(4)	(7)	(3)	(3)	–	(8)	(10)	19	9	1
Revisions – Economic	229	(12)	4	6	(10)	219	–	(2)	–	–	–
Production	(38)	(74)	(19)	(6)	(33)	–	(5)	(34)	(6)	(7)	(2)
December 31, 2006	**549**	**532**	**38**	**48**	**314**	**219**	**30**	**195**	**179**	**23**	**35**
Extensions and Discoveries	13	51	1	1	31	–	1	18	10	2	–
Purchases of Reserves in Place	3	42	–	–	1	–	2	41	1	–	–
Sales of Reserves in Place	–	(10)	–	–	–	–	–	(10)	–	–	–
Revisions – Technical	53	–	–	(1)	11	19	(4)	(19)	39	8	–
Revisions – Economic	–	(11)	(2)	4	(4)	(4)	(2)	(5)	4	(2)	–
Production	(57)	(72)	(14)	(5)	(35)	–	(6)	(31)	(30)	(6)	(2)
December 31, 2007	**561**	**532**	**23**	**47**	**318**	**234**	**21**	**189**	**203**	**25**	**33**
Extensions and Discoveries	26	39	1	1	34	19	–	5	5	–	–
Purchases of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions – Technical	20	40	6	(3)	54	–	2	(14)	17	–	(2)
Revisions – Economic	(3)	(21)	2	(19)	(16)	31	(3)	(5)	(16)	–	2
Production	(60)	(71)	(12)	(4)	(40)	(2)	(3)	(24)	(37)	(7)	(2)
December 31, 2008	**544**	**519**	**20**	**22**	**350**	**282**	**17**	**151**	**172**	**18**	**31**
Proved Developed Reserves [5]											
December 31, 2006	286	460	33	44	287	40	28	161	131	12	10
December 31, 2007	281	423	22	44	293	40	17	114	151	16	7
December 31, 2008	**244**	**464**	**19**	**22**	**329**	**52**	**12**	**124**	**133**	**11**	**6**

1 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.

2 Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves to be sold.

3 Represents reserves in Nigeria and Colombia.

4 Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.

5 Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 are on pages 20 through 22. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling density of less than 500 metres. In accordance with the approved mining plan, there are an estimated 2 billion tons of economically extractable oil sands in the Mildred Lake North Mine, with an average bitumen grade of 10.3 weight percent. The Aurora North Mine contains an estimated 4.6 million tons of economically extractable oil sands at an average bitumen grade of 11.1 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 3.8 billion tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	**Mildred Lake** [1]	**Aurora** [2]	**Total**
December 31, 2005	**47**	**217**	**264**
Extensions and Discoveries	–	11	11
Revision – Economic	1	4	5
Production	(3)	(3)	(6)
December 31, 2006	**45**	**229**	**274**
Extensions and Discoveries	–	7	7
Revision – Economic	–	(7)	(7)
Production	(3)	(4)	(7)
December 31, 2007	**42**	**225**	**267**
Extensions and Discoveries	–	7	7
Revision – Economic	11	17	28
Production	(4)	(3)	(7)
December 31, 2008	**49**	**246**	**295**

1 Leases 17 and 22.
2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2008				
Yemen	2,808	–	(2,610)	198
Canada	5,087	1,067	(2,179)	3,975
United States	4,152	246	(2,702)	1,696
United Kingdom	5,954	578	(2,159)	4,373
Other Countries	509	45	(113)	441
Total Capitalized Costs	**18,510**	**1,936**	**(9,763)**	**10,683**
December 31, 2007				
Yemen	2,178	–	(1,950)	228
Canada	4,364	734	(1,990)	3,108
United States	2,931	138	(1,765)	1,304
United Kingdom	4,318	405	(908)	3,815
Other Countries	105	158	(77)	186
Total Capitalized Costs	**13,896**	**1,435**	**(6,690)**	**8,641**
December 31, 2006				
Yemen	2,404	–	(2,128)	276
Canada	3,787	227	(1,467)	2,547
United States	2,768	121	(1,445)	1,444
United Kingdom	4,325	385	(432)	4,278
Other Countries	99	150	(78)	171
Total Capitalized Costs	**13,383**	**883**	**(5,550)**	**8,716**

C. Costs Incurred (excluding Syncrude operations)

		Oil and Gas				
(Cdn$ millions)	Total Oil and Gas	Yemen	Canada	United States	United Kingdom	Other
Year Ended December 31, 2008						
Property Acquisition Costs						
Proved	22	–	22	–	–	–
Unproved	69	–	6	63	–	–
Exploration Costs	650	9	222	132	157	130
Development Costs	1,795	92	717	251	545	190
Asset Retirement Costs	188	–	25	153	10	–
Total Costs Incurred	**2,724**	**101**	**992**	**599**	**712**	**320**
Year Ended December 31, 2007						
Property Acquisition Costs						
Proved	151	–	1	104	46	–
Unproved	59	–	34	24	1	–
Exploration Costs	637	15	93	311	128	90
Development Costs	1,817	124	675	414	551	53
Asset Retirement Costs	169	6	48	30	85	–
Total Costs Incurred	**2,833**	**145**	**851**	**883**	**811**	**143**
Year Ended December 31, 2006						
Property Acquisition Costs						
Proved	13	–	12	–	1	–
Unproved	125	–	105	19	1	–
Exploration Costs	514	37	74	242	71	90
Development Costs	2,051	145	884	399	595	28
Asset Retirement Costs	69	4	5	4	56	–
Total Costs Incurred	**2,772**	**186**	**1,080**	**664**	**724**	**118**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Oil and Gas	Oil and Gas: Yemen	Canada	United States	United Kingdom	Other Countries
Year Ended December 31, 2008						
Net Sales	6,186	1,093	656	665	3,580	192
Production Costs	715	176	182	94	253	10
Exploration Expense	402	5	79	109	86	123
Depreciation, Depletion, Amortization and Impairment	1,859	160	208	475	999	17
Other Expenses (Income)	75	(10)	29	37	6	13
	3,135	762	158	(50)	2,236	29
Income Tax Provision (Recovery)	1,412	264	45	(19)	1,126	(4)
Results of Operations	**1,723**	**498**	**113**	**(31)**	**1,110**	**33**
Year Ended December 31, 2007						
Net Sales	4,576	1,086	441	616	2,285	148
Production Costs	668	171	175	102	212	8
Exploration Expense	326	5	27	134	69	91
Depreciation, Depletion, Amortization and Impairment	1,627	213	166	641	599	8
Other Expenses (Income)	100	(8)	66	38	(36)	40
	1,855	705	7	(299)	1,441	1
Income Tax Provision (Recovery)	859	248	2	(103)	712	–
Results of Operations	**996**	**457**	**5**	**(196)**	**729**	**1**
Year Ended December 31, 2006						
Net Sales	3,032	1,328	459	629	477	139
Production Costs	491	151	146	106	80	8
Exploration Expense	362	4	26	214	46	72
Depreciation, Depletion, Amortization and Impairment	1,011	327	162	296	216	10
Other Expenses (Income)	71	15	106	(23)	(71)	44
	1,097	831	19	36	206	5
Income Tax Provision	687	289	6	13	378	1
Results of Operations	**410**	**542**	**13**	**23**	**(172)**	**4**

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved oil and gas reserves (excluding Syncrude operations). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2008						
Future Cash Inflows	25,305	904	12,260	1,809	8,753	1,579
Future Production Costs	10,847	424	6,619	765	2,616	423
Future Development Costs	3,008	51	1,488	33	564	872
Future Dismantlement and Site Restoration Costs, Net	1,421	20	332	446	558	65
Future Income Tax	2,653	141	–	–	2,467	45
Future Net Cash Flows	7,376	268	3,821	565	2,548	174
10% Discount Factor	2,953	24	1,988	84	505	352
Standardized Measure	**4,423**	**244**	**1,833**	**481**	**2,043**	**(178)**
December 31, 2007						
Future Cash Inflows	43,888	1,952	17,365	3,207	17,977	3,387
Future Production Costs	11,988	468	7,229	539	3,347	405
Future Development Costs	3,229	22	957	328	778	1,144
Future Dismantlement and Site Restoration Costs, Net	1,143	16	273	197	595	62
Future Income Tax	8,793	452	1,135	437	6,589	180
Future Net Cash Flows	18,735	994	7,771	1,706	6,668	1,596
10% Discount Factor	7,606	111	4,236	441	1,561	1,257
Standardized Measure	**11,129**	**883**	**3,535**	**1,265**	**5,107**	**339**
December 31, 2006						
Future Cash Inflows	32,247	2,330	12,678	3,151	11,437	2,651
Future Production Costs	9,523	606	5,615	791	2,236	275
Future Development Costs	3,190	115	1,156	332	891	696
Future Dismantlement and Site Restoration Costs, Net	1,006	11	289	197	471	38
Future Income Tax	5,204	489	753	450	3,308	204
Future Net Cash Flows	13,324	1,109	4,865	1,381	4,531	1,438
10% Discount Factor	4,951	106	2,484	321	970	1,070
Standardized Measure	**8,373**	**1,003**	**2,381**	**1,060**	**3,561**	**368**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2008	2007	2006
Beginning of Year	11,129	8,373	8,042
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(4,387)	(3,010)	(2,291)
Net Changes in Prices and Production Costs Related to Future Production	(9,756)	3,385	(1,065)
Extensions, Discoveries and Improved Recovery, Less Related Costs	376	758	695
Changes in Estimated Future Development and Dismantlement Costs	(676)	(443)	(692)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	1,343	1,102	1,048
Revisions of Previous Quantity Estimates	615	2,189	1,936
Accretion of Discount	1,730	1,191	1,117
Purchases of Reserves in Place	–	272	2
Sales of Reserves in Place	–	(49)	(2)
Net Change in Income Taxes	4,049	(2,639)	(417)
End of Year	**4,423**	**11,129**	**8,373**

ITEM 9.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There were no disagreements with accountants on accounting and financial disclosure.

ITEM 9A.

Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), or caused such disclosure controls and procedures to be designed under their supervision, to ensure that material information relating to the Company is made known to them, particularly during the period in which this report is prepared. They have evaluated the effectiveness of such disclosure controls and procedures as of the end of the period covered by this report (Evaluation Date). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective (i) to ensure that information required to be disclosed by us in reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms; and (ii) to ensure that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is accumulated and communicated to our management, including the Company's Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

The Company's management, including its Chief Executive Officer and Chief Financial Officer, does not expect that the Company's disclosure controls and procedures or internal controls will prevent all possible error and fraud. The Company's disclosure controls and procedures are, however, designed to provide reasonable assurance of achieving their objectives, and the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's financial controls and procedures are effective at that reasonable assurance level.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2008. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report which is on page 132 of this Form 10-K and has issued an attestation report on our internal control over financial reporting.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems of internal controls over financial reporting. There have not been any changes in the Company's internal control over financial reporting during the last quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. As well, no material weaknesses requiring corrective action were identified in the conduct of our evaluation of internal control over financial reporting. As a result, no such corrective actions were taken.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the internal control over financial reporting of Nexen Inc. 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 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 of the Company as of and for the year ended December 31, 2008, and our report dated February 11, 2009, expressed an unqualified opinion on those financial statements and includes a separate report titled Comments by Independent Registered Chartered Accountants on Canada—United States of America Reporting Difference referring to changes in accounting principles that have a material effect on the comparability of the Company's financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 2009