CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Consolidated Balance Sheets

(millions of Canadian dollars) (unaudited)		March 31, 2011		December 31, 2010 *(note 15)*		January 1, 2010 *(note 15)*
Assets						
Current assets						
Cash and cash equivalents *(note 5)*	$	58	$	252	$	392
Accounts receivable		1,757		1,529		987
Inventories		1,765		1,935		1,520
Prepaid expenses		27		34		12
Asset held for sale *(note 14)*		59		-		-
		3,666		3,750		2,911
Non-current assets						
Exploration and evaluation assets *(note 6)*		524		472		1,943
Property, plant and equipment, net *(note 7)*		22,599		21,770		18,584
Goodwill		651		663		689
Contribution receivable *(note 13)*		1,242		1,284		1,313
Other assets, including derivatives *(note 13)*		111		111		68
Total Assets	$	28,793	$	28,050	$	25,508
Liabilities and Shareholders' Equity						
Current liabilities						
Accounts payable and accrued liabilities	$	2,575	$	2,506	$	1,941
Income taxes payable		-		-		270
Asset retirement obligations *(note 10)*		40		63		29
		2,615		2,569		2,240
Long-term debt *(note 9)*		4,085		4,187		3,229
Other long-term financial liabilities *(note 13)*		126		102		96
Other long-term liabilities		281		289		284
Contribution payable *(note 13)*		1,394		1,427		1,500
Deferred tax liabilities		3,939		3,767		3,705
Asset retirement obligations *(note 10)*		1,197		1,135		738
Commitments and contingencies *(note 12)*						
Total Liabilities		13,637		13,476		11,792
Shareholders' equity						
Common shares *(note 11)*		4,574		4,574		3,585
Preferred shares *(note 11)*		291		-		-
Retained earnings		10,385		10,026		10,099
Other reserves		(94)		(26)		32
Total Shareholders' Equity		15,156		14,574		13,716
Total Liabilities and Shareholders' Equity	$	28,793	$	28,050	$	25,508

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

Condensed Consolidated Statements of Income

(millions of Canadian dollars, except share data) (unaudited)	Three months ended March 31 2011	2010 (note 15)
Gross revenues	$ 5,860	$ 4,493
Royalties	(258)	(286)
Revenues, net of royalties	5,602	4,207
Expenses		
Purchases of crude oil and products	3,508	2,544
Production and operating expenses	609	572
Selling, general and administrative expenses	86	47
Depletion, depreciation and amortization *(note 7)*	542	449
Exploration and evaluation expenses *(note 6)*	93	52
Other – net *(notes 8, 13)*	(170)	27
	4,668	3,691
Earnings from operating activities	934	516
Financial items *(note 9)*		
Net foreign exchange gains	2	30
Finance income	21	23
Finance expenses	(85)	(78)
	(62)	(25)
Earnings before income taxes	872	491
Provisions for income taxes		
Current	70	78
Deferred	176	45
	246	123
Net earnings	$ 626	$ 368
Earnings per share		
Basic	$ 0.70	$ 0.43
Diluted	$ 0.70	$ 0.41
Weighted average number of common shares outstanding *(millions)*		
Basic	890.7	849.9
Diluted	897.2	849.9

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

Condensed Consolidated Statements of Other Comprehensive Income

(millions of Canadian dollars) (unaudited)	Three months ended March 31 2011	2010 (note 15)
Net earnings	$ 626	$ 368
Other comprehensive income (loss)		
Derivatives designated as cash flow hedges, net of tax	(14)	4
Actuarial gains on pension plans, net of tax	4	3
Exchange differences on translation of foreign operations	(77)	(118)
Hedge of net investment, net of tax	19	25
Other comprehensive income (loss)	(68)	(86)
Comprehensive income	$ 558	$ 282
Total comprehensive income attributable to:		
Owners of the company	$ 558	$ 282

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(millions of Canadian dollars) (unaudited)	Common Shares (note 11)	Preferred Shares (note 11)	Retained Earnings	Other Reserves	Total Shareholders' Equity
	Attributable to Equity Holders				
Balance as at January 1, 2010	$ 3,585	$ -	$ 10,099	$ 32	$ 13,716
Net earnings for the period	-	-	368	-	368
Other comprehensive income (loss):					
Derivatives designated as cash flow hedges, net of tax	-	-	-	4	4
Actuarial gains on pension plans, net of tax	-	-	-	3	3
Exchange differences on translation of foreign operations	-	-	-	(118)	(118)
Hedge of net investment, net of tax	-	-	-	25	25
Other comprehensive income (loss)	-	-	-	(86)	(86)
Transactions with owners recognized directly in equity					
Dividends declared on common shares	-	-	(255)	-	(255)
Balance as at March 31, 2010	$ 3,585	$ -	$ 10,212	$ (54)	$ 13,743
Balance as at January 1, 2011	$ 4,574	$ -	$ 10,026	$ (26)	$ 14,574
Net earnings for the period	-	-	626	-	626
Other comprehensive income (loss):					
Derivatives designated as cash flow hedges, net of tax	-	-	-	(14)	(14)
Actuarial gains (losses) on pension plans, net of tax	-	-	-	4	4
Exchange differences on translation of foreign operations	-	-	-	(77)	(77)
Hedge of investment, net of tax	-	-	-	19	19
Other comprehensive income (loss)	-	-	-	(68)	(68)
Transactions with owners recognized directly in equity					
Issue of preferred shares *(note 11)*	-	300	-	-	300
Share issue costs *(note 11)*	-	(9)	-	-	(9)
Dividends declared on common shares	-	-	(267)	-	(267)
Balance as at March 31, 2011	$ 4,574	$ 291	$ 10,385	$ (94)	$ 15,156

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

Condensed Consolidated Statements of Cash Flows

	Three months ended March 31	
(millions of Canadian dollars) (unaudited)	2011	2010
Operating activities		
Net earnings for the period	$ 626	$ 368
Items not affecting cash:		
Accretion	19	15
Depletion, depreciation and amortization	542	449
Exploration and evaluation expenses	1	-
Deferred income taxes	176	45
Foreign exchange	(11)	(40)
Stock-based compensation	5	(11)
Gain on sale of property, plant and equipment	(189)	-
Other	(5)	28
Settlement of asset retirement obligations	(23)	(15)
Income taxes paid	(21)	(599)
Change in non-cash working capital *(note 5)*	163	321
Cash flow – operating activities	1,283	561
Financing activities		
Long-term debt issue	4,094	1,334
Long-term debt repayment	(4,114)	(634)
Debt issue costs	-	(4)
Proceeds from preferred share issuance, net of transaction costs	291	-
Dividends on common shares	(255)	(255)
Interest paid	(18)	(20)
Capitalized interest paid	(17)	(4)
Other	36	3
Change in non-cash working capital *(note 5)*	60	54
Cash flow – financing activities	77	474
Investing activities		
Capital expenditures	(1,558)	(679)
Proceeds from asset sales	112	3
Other	(27)	(50)
Change in non-cash working capital *(note 5)*	(81)	(195)
Cash flow – investing activities	(1,554)	(921)
Increase (decrease) in cash and cash equivalents	(194)	114
Effect of exchange rates on cash and cash equivalents	-	(4)
Cash and cash equivalents at beginning of period	252	392
Cash and cash equivalents at end of period	$ 58	$ 502

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

Note 1 Nature of Operations and Organization

Husky Energy Inc. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada. The condensed interim consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries after the elimination of intercompany balances and transactions. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies as to obtain benefits from their activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the condensed interim consolidated financial statements.

Note 2 Segmented Financial Information

Management has segmented the Company's business based on differences in products and services and management responsibility. The Company's business is conducted predominantly through three major business segments - Upstream, Midstream and Downstream.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's Upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore Greenland, offshore China and offshore Indonesia.

Midstream includes marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (upgrading), refining in Canada of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian refined products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. refining and marketing).

In the first quarter of 2011, the Company commenced evaluating and reporting its upgrading activities as part of Downstream operations. As a result, upgrading was moved from the Midstream segment to the Downstream segment. All prior periods have been restated to conform to these segment definitions.

Except where indicated and per share amounts, all dollar amounts are in millions.

Segmented Financial Information

	Upstream		Midstream Infrastructure and Marketing		Downstream Upgrading	
	2011	2010	**2011**	2010	**2011**	2010
Three months ended March 31						
Gross revenues	**$ 1,671**	$ 1,538	**$ 2,368**	$ 1,826	**$ 368**	$ 508
Royalties	**(258)**	(286)	**-**	-	**-**	-
Revenues, net of royalties	**1,413**	1,252	**2,368**	1,826	**368**	508
Expenses						
Purchases of crude oil and products	**-**	-	**2,203**	1,667	**269**	418
Production and operating expenses	**393**	343	**34**	46	**58**	49
Selling, general and administrative expenses	**42**	29	**6**	5	**-**	-
Depletion, depreciation and amortization	**432**	346	**10**	10	**25**	3
Exploration and evaluation expenses	**93**	49	**-**	-	**-**	-
Other - net	**(189)**	1	**10**	31	**10**	(7)
Earnings from operating activities	**642**	484	**105**	67	**6**	45
Net foreign exchange gains	**-**	-	**-**	-	**-**	-
Finance income	**1**	-	**-**	-	**-**	-
Finance expenses	**(15)**	(10)	**-**	-	**(2)**	(3)
	(14)	(10)	**-**	-	**(2)**	(3)
Earnings before income taxes	**628**	474	**105**	67	**4**	42
Provisions for (recovery of) income taxes						
Current	**20**	16	**20**	15	**1**	10
Deferred	**152**	121	**6**	3	**-**	2
	172	137	**26**	18	**1**	12
Net earnings for the period	**$ 456**	$ 337	**$ 79**	$ 49	**$ 3**	$ 30
Intersegment revenues	**$ 1,356**	$ 1,447	**$ 186**	$ 184	**$ 24**	$ 27
Other material non-cash items						
Unrealized loss on gas storage contracts	**-**	-	**21**	29	**-**	-
Gain on sale of property, plant and equipment	**(189)**	-	**-**	-	**-**	-
Exploration and evaluation assets and property, plant and equipment – As at March 31, 2011 and December 31, 2010						
Exploration and evaluation assets	**$ 524**	$ 472	**$ -**	$ -	**$ -**	$ -
Developing and producing assets at cost	**30,616**	29,144	**-**	-	**-**	-
Accumulated depletion, depreciation and amortization	**(14,342)**	(13,917)	**-**	-	**-**	-
Other property, plant and equipment at cost	**-**	-	**969**	1,069	**1,984**	1,974
Accumulated depletion, depreciation and amortization	**-**	-	**(416)**	(450)	**(768)**	(743)
Exploration and evaluation assets and property, plant and equipment, net	**$ 16,798**	$ 15,699	**$ 553**	$ 619	**$ 1,216**	$ 1,231
Expenditures on property, plant and equipment -Three months ended March 31 (2)	**$ 1,390**	$ 393	**$ 6**	$ 3	**$ 10**	$ 9
Expenditures on exploration and evaluation assets - Three months ended March 31 (2)	**122**	233	**-**	-	**-**	-
Total assets - As at March 31, 2011 and December 31 2010	**18,631**	17,245	**1,717**	1,374	**1,335**	1,936

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment net earnings in inventories.*
(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Except where indicated and per share amounts, all dollar amounts are in millions.

Downstream (continued)				Corporate and Eliminations [1]		Total	
Canadian Refined Products		U.S. Refining and Marketing					
2011	2010	**2011**	2010	**2011**	2010	**2011**	2010
$ 833	$ 606	**$ 2,224**	$ 1,719	**$ (1,604)**	$ (1,704)	**$ 5,860**	$ 4,493
-	-	**-**	-	**-**	-	**(258)**	(286)
833	606	**2,224**	1,719	**(1,604)**	(1,704)	**5,602**	4,207
713	516	**1,896**	1,623	**(1,573)**	(1,680)	**3,508**	2,544
42	40	**92**	92	**(10)**	2	**609**	572
13	13	**2**	1	**23**	(1)	**86**	47
18	25	**50**	46	**7**	19	**542**	449
-	-	**-**	-	**-**	3	**93**	52
-	-	**-**	2	**(1)**	-	**(170)**	27
47	12	**184**	(45)	**(50)**	(47)	**934**	516
-	-	**-**	-	**2**	30	**2**	30
-	-	**-**	-	**20**	23	**21**	23
(1)	(1)	**(1)**	(1)	**(66)**	(63)	**(85)**	(78)
(1)	(1)	**(1)**	(1)	**(44)**	(10)	**(62)**	(25)
46	11	**183**	(46)	**(94)**	(57)	**872**	491
4	15	**-**	-	**25**	22	**70**	78
8	(12)	**67**	(17)	**(57)**	(52)	**176**	45
12	3	**67**	(17)	**(32)**	(30)	**246**	123
$ 34	$ 8	**$ 116**	$ (29)	**$ (62)**	$ (27)	**$ 626**	$ 368
$ 38	$ 46	**$ -**	$ -	**$ -**	$ -	**$ 1,604**	$ 1,704
-	-	**-**	-	**-**	-	**21**	29
-	-	**-**	-	**-**	-	**(189)**	-
$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ 524**	$ 472
-	-	**-**	-	**-**	-	**30,616**	29,144
-	-	**-**	-	**-**	-	**(14,342)**	(13,917)
2,092	2,085	**3,912**	4,001	**492**	487	**9,449**	9,616
(946)	(929)	**(586)**	(551)	**(408)**	(400)	**(3,124)**	(3,073)
$ 1,146	$ 1,156	**$ 3,326**	$ 3,450	**$ 84**	$ 87	**$ 23,123**	$ 22,242
$ 15	$ 16	**$ 22**	$ 21	**$ 3**	$ 2	**$ 1,446**	$ 444
-	-	**-**	-	**-**	-	**122**	233
1,569	1,517	**5,034**	5,092	**507**	886	**28,793**	28,050

Except where indicated and per share amounts, all dollar amounts are in millions.

Geographical Financial Information

	Canada		United States		Other International		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010
Period ended March 31								
Gross revenues	**$ 3,008**	$ 2,386	**$ 2,772**	$ 2,030	**$ 80**	$ 77	**$ 5,860**	$ 4,493
Royalties	**(236)**	(268)	**-**	-	**(22)**	(18)	**(258)**	(286)
Revenue, net of royalties	**$ 2,772**	$ 2,118	**$ 2,772**	$ 2,030	**$ 58**	$ 59	**$ 5,602**	$ 4,207
As at March 31, 2011 and December 31, 2010								
Exploration and evaluation assets	**$ 341**	$ 252	**$ 44**	$ -	**$ 139**	$ 220	**$ 524**	$ 472
Property, plant and equipment, net	**18,591**	17,723	**3,326**	3,451	**682**	596	**22,599**	21,770
Goodwill	**160**	160	**491**	503	**-**	-	**651**	663
Total non-current assets	**20,421**	19,534	**3,885**	3,950	**821**	816	**25,127**	24,300

Note 3 Basis of Presentation

a) Statement of Compliance

These condensed interim consolidated financial statements have been prepared by management and reported in Canadian dollars in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting." These are the Company's first International Financial Reporting Standards ("IFRS") condensed interim consolidated financial statements for part of the period covered by the first IFRS annual financial statements and IFRS 1, "First-time Adoption of International Financial Reporting Standards," has been applied. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements.

Note 15 provides an explanation of how the transition to IFRS has affected the reported financial position and performance. This note includes reconciliations of equity and total comprehensive income for comparative periods, and a reconciliation of equity at the date of the transition from Canadian generally accepted accounting principles ("GAAP") to IFRS.

The condensed interim consolidated financial statements of the Company for the periods ended March 31, 2011 and 2010 and as at March 31 2011, March 31 2010, December 31, 2010 and January 1, 2010 were approved and signed by the Chair of the Audit Committee and Chief Executive Officer on April 26, 2011 having been duly authorized to do so by the Board of Directors.

b) Basis of Measurement and Principles of Consolidation

The condensed interim consolidated financial statements have been prepared on a historical cost basis with some exceptions in accordance with IAS 34, "Interim Financial Reporting," as detailed in the accounting policies set out below. These policies have been applied consistently for all periods presented in these condensed interim consolidated financial statements and in preparing the opening IFRS balance sheet as at January 1, 2010 (subject to certain exceptions allowed by IFRS 1) for the purpose of the transition to IFRS. See Note 15 for details of the transition to IFRS.

Substantially all of the Company's Upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

c) Use of Estimates, Judgments and Assumptions

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the Company's operating environment changes.

Specifically, amounts recorded for depletion, depreciation and amortization expense, accretion expense, asset retirement obligations, fair value measurements, employee future benefits and amounts used in impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions.

d) Functional and Presentation Currency

These condensed interim consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is presented in millions of Canadian dollars unless otherwise stated.

Note 4 Significant Accounting Policies

a) Cash and Cash Equivalents

Cash and cash equivalents in the balance sheet and for the purposes of the statement of cash flows consist of cash on hand less outstanding cheques and deposits with a maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand and the Company has the ability to net settle, the excess is reported in bank operating loans.

b) Inventories

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Commodity inventories held for trading purposes are carried at fair value less costs to sell. Any changes in fair value are included as gains or losses in other expenses during the period of change. Previous impairment provisions are reversed when there is a change in the situation that caused the impairment. Unrealized intersegment net earnings in inventories are eliminated.

c) Precious Metals

The Company uses precious metals in conjunction with catalyst as part of the downstream U.S. refining process. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in earnings.

d) Exploration and Evaluation Assets and Property, Plant and Equipment

i) Cost

Oil and gas properties and other property, plant and equipment are stated at cost.

The chosen accounting policy requires management to determine the proper classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment of the costs incurred for oil and natural gas exploration, evaluation and development expenditures.

The results from an exploration drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Exploration drilling costs can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk associated with drilling in particular areas. Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance.

ii) Pre-license costs

Pre-license costs are expensed in the period in which they are incurred.

iii) Exploration and evaluation costs

Costs associated with acquiring an exploration licence, including costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees are capitalized as exploration and evaluation assets. Geological and geophysical costs associated with exploration licences are charged to earnings as incurred. Land acquisition costs and expenditures directly associated with exploratory wells are capitalized and remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Land acquisition costs associated with successful exploration are reclassified into property, plant and equipment. Costs directly associated with an exploration well are capitalized as exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated.

If extractable hydrocarbons are found and are likely to be developed commercially, subject to further appraisal activity which may include the drilling of further wells, the costs continue to be carried as an intangible asset while sufficient and continued progress is made in assessing the commerciality of the hydrocarbons. All such carried costs are subject to technical, commercial and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When technical feasibility and commercial viability is determined and development is sanctioned, the relevant expenditure is transferred to oil and gas properties after impairment is assessed and any resulting impairment loss if applicable is recognized. Impairment is recorded when the carrying value of the properties exceeds fair value. If no reserves are found, the capitalized exploration costs are charged to expense as dry hole costs.

iv) Development costs

Expenditures, including borrowing costs, on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, are capitalized within oil and gas properties. Costs incurred to operate and maintain wells and equipment, and to lift oil and gas to the surface, are expensed as operating costs.

v) Other property, plant and equipment

Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Certain turnaround costs are capitalized as part of property, plant and equipment when incurred and are amortized over the estimated period of time to the next scheduled turnaround.

vi) Depreciation, depletion and amortization

Oil and gas properties are depreciated on a unit-of-production basis over the proved developed reserves of the particular field, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total recoverable reserves is applied. Rights and concessions are depleted on the unit-of-production basis over the total proved reserves of the relevant area. The unit-of-production rate for the amortization of oil and gas properties directly related to proved reserves field development takes into account expenditures incurred to date, together with sanctioned future development expenditures.

Oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depreciation, depletion and amortization expense, in addition to determining possible write-downs of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting Crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as required, as at the balance sheet date, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets, which range from five to thirty-five years, and any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

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

Any gain or loss arising on disposals of non-oil and gas properties is included in earnings in the period of disposal.

e) Joint Arrangements

Joint ventures are those entities over which activities the Company has joint control established by contractual agreement. The consolidated financial statements include the Company's proportionate share of the entities' assets, liabilities, revenue and expenses with items of a similar nature on a line-by-line basis, from the date that joint control commences until the date that joint control ceases.

f) Business Combinations

Business combinations are accounted for using the acquisition method. Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case by case basis. If the acquisition meets the definition of a business combination, the assets and liabilities are classified or designated based on the contractual terms, economic conditions, the Company's operating and accounting policies, and other factors that exist on the acquisition date. The identifiable assets and liabilities are measured at their fair values on the acquisition date. Any contingent liabilities are also recognized on the acquisition date even if it is not probable that an outflow of resources will be required to settle the obligation. Acquisition costs incurred are expensed and included in other expenses.

g) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill, which is not amortized, is assigned to appropriate cash generating units ("CGUs") or groups of CGUs. Since goodwill results from the culmination of purchase accounting, it is inherently imprecise and requires judgment in the determination of the fair value of assets and liabilities. Goodwill is tested for impairment annually and when circumstances indicate that the carrying value may be impaired. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal. Impairment losses are recognized in the current period income. An impairment loss with respect to goodwill is not reversed.

h) Impairment of Non-financial Assets

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If such indication exists, then the recoverable amount is estimated. For goodwill and other intangible assets that have indefinite lives or that are not yet available for use, the recoverable amount is estimated during the fourth quarter of each year or when any indication of impairment exists.

Carrying values of oil and gas properties and other property, plant and equipment are reviewed for impairment when indicators of such impairment exist. External factors, such as an extended decrease in prices or margins for oil and gas commodities or products, a significant downward revision of estimated volumes or upward revision of future development costs, are also monitored as possible indications of impairment. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated. The recoverable amount of an asset is determined as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. In that situation, the assets are tested as part of a CGU, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

FVLCS is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

VIU is determined as the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account approved future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, marketing supply and demand, product margins and, in the case of oil and gas properties, expected production volumes. The latter takes into account assessments of field reservoir performance and includes expectations about proved and unproved volumes, which are risk-weighted utilizing geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Husky's credit risk-adjusted discount rate. These assumptions are different to those used in calculating fair value.

These calculations for recoverable amounts require the use of estimates and assumptions. It is possible that the assumptions may change, which may impact the estimated life of the field and may require a material adjustment to the carrying value of goodwill and tangible assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the CGU or group of CGUs on a pro rata basis. Impairment losses are recognized in depletion, depreciation and amortization.

Impairment losses recognized for other assets in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the asset's or CGU's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

i) Asset Retirement Obligations ("ARO")

A liability is recognized for future legal or constructive retirement obligations associated with the Company's property, plant and equipment. The amount recognized is the net present value of the estimated future expenditures determined in accordance with local conditions, current technology and current requirements. The obligation is calculated using the current estimated costs to retire the asset inflated to the estimated retirement date and then discounted using a credit-adjusted risk free discount rate. The liability is recorded in the period in which an obligation arises with a corresponding increase to the carrying value of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an expense recognized as part of finance expenses.

Liabilities for ARO are also adjusted for changes in estimates. Those adjustments are accounted for as a change in the corresponding capitalized cost, except where a reduction in the provision is greater than the undepreciated capitalized cost of the related assets, in which case the capitalized cost is reduced to nil and the remaining adjustment is recognized in earnings. In the case of closed sites, changes to estimated costs are recognized immediately in earnings. Changes to the capitalized cost result in an adjustment to future depreciation and finance expenses. Adjustments to the estimated amount and timing of future ARO cash flows are a normal occurrence in light of the significant judgments and estimates involved.

The costs capitalized to the related assets are amortized in a manner consistent with the depletion, depreciation and amortization of the underlying assets. Actual retirement expenditures are charged against the accumulated liability as incurred.

The Company has significant obligations to remove tangible assets and restore land after operations cease and the Company retires or relinquishes the asset. The Company's ARO primarily relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities, and restoration of land to a state required by regulation or contract. Estimating the ARO requires that the Company estimate costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the calculation of the ARO are numerous assumptions and judgment including the ultimate settlement amounts, future third-party pricing, inflation factors, risk free discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the ARO liability.

j) Legal and Other Contingent Matters

Provisions and liabilities for legal and other contingent matters are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of the cash outflow can be reasonably estimated. The timing of recognition and measurement of the provision requires the application of judgment to existing facts and circumstances, which can be subject to change. The carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances. The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When a loss is determined it is charged to earnings. The Company must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

k) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects. Preferred shares are classified as equity since they are redeemable at the Company's option. Common dividends are paid out in common shares or in cash and are recognized as distributions within equity.

l) Financial Instruments

Financial instruments must initially be recognized at fair value on the balance sheet based on their initial classification. Each financial instrument is classified as one of the following categories: financial assets and financial liabilities measured at fair value through profit or loss, loans or receivables, held to maturity investments, available-for-sale financial assets, or other financial liabilities.

Financial assets include cash and cash equivalents, accounts receivable, contribution receivable, and derivative financial instruments. Financial liabilities include accounts payable and accrued liabilities, contribution payable, long-term debt, other long-term financial liabilities and derivative financial instruments.

A financial instrument measured at fair value through profit and loss ("FVTPL") is not a loan or receivable and includes one of the following criteria:

- is a derivative, except for derivatives that have been designated as effective hedging instruments;
- has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of realized short-term trading margins.

For financial assets and financial liabilities that are not classified as FVTPL, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to the fair value initially recognized for that financial instrument. These costs are expensed to earnings using the effective interest rate method.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest rate method if the time value of money is significant.

Subsequent measurement of a financial instrument is based on its classification. Unrealized gains and losses on available-for-sale financial assets are recognized in other comprehensive income ("OCI") and are transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

m) Derivative Instruments and Hedging Activities

Derivative instruments are utilized by the Company to manage market risk associated with the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting is optional.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments, are classified as FVTPL and are recorded on the balance sheet at fair value in accounts receivable, other assets, accounts payable and accrued liabilities or other long-term financial liabilities. The fair value of other long-term financial liabilities is the present value of future cash flows associated with the obligation. Freestanding derivative instruments are classified as FVTPL financial instruments. Gains and losses on these instruments are recorded in other expenses in the period they occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers to retain market prices while meeting customer or supplier pricing requirements. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. Gains and losses from these contracts are recognized in midstream revenues or purchases of crude oil and products.

The Company may enter into foreign exchange contracts to offset its foreign exchange exposure. Gains and losses on these instruments are recorded at fair value and are recognized in other expenses.

Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative and the combined contract is not measured at FVTPL. Embedded derivatives are measured at fair value with gains and losses recognized in earnings.

ii) Hedging Activities

At the inception of a hedge, if the Company elects to use hedge accounting, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the hedged items and hedging items and the method for testing the effectiveness of the hedge, which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Derivative instruments that have been designated and qualify for hedge accounting are classified as either fair value or cash flow hedges.

The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in earnings along with the gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in OCI until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the Condensed Interim Consolidated Statements of Income and Condensed Interim Consolidated Statements of Other Comprehensive Income, the fair value of the associated cash flow hedge is reclassified from OCI into earnings. Any hedge ineffectiveness is immediately recognized in earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting.

The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax, and are limited to the translation gain or loss on the net investment.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. The estimate of fair value of interest rate hedges is determined primarily through forward market prices and compared with quotes from financial institutions. Gains and losses from these contracts are recognized as an adjustment to the finance expense on the hedged debt instrument.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. The estimation of fair value of forward purchases of U.S. dollars is determined using forward market prices. Gains and losses on these instruments related to foreign exchange are recorded in foreign exchange gains or losses in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in other reserves and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated crude oil and natural gas sales. The estimate of fair value for foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. Gains and losses on these instruments are recognized in upstream oil and gas revenues when the sale is recorded.

n) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, exchange gains and losses arising from the translation of the financial statements of foreign operations and actuarial gains and losses on defined benefit pension plans. Amounts included in OCI are shown net of tax. Other reserves is an equity category comprised of the cumulative amounts of OCI.

o) Impairment of Financial Assets

A financial asset is assessed at each reporting date to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the net present value of the estimated future cash flows discounted at the original effective interest rate. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its fair value and any amounts in OCI are transferred to earnings.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

p) Pensions and Other Post-Employment Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides defined contribution plans (401(k)), a defined benefit pension plan and other post-retirement benefits.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the defined benefit pension plans is determined using the projected unit credit funding method. Actuarial gains and losses are recognized in OCI as incurred.

Past service costs are recognized in the benefit cost on a straight-line basis over the average period until the benefits become vested. The past service costs are recognized as an expense immediately following the introduction of, or changes to, the pension plans.

The defined benefit asset or liability comprises the present value of the defined benefit obligation, less past service costs and the fair value of plan assets from which the obligations are to be settled. Plan assets are measured at fair value based on the closing bid price when there is a quoted price in an active market. Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the Company's creditors. The value of any defined benefit asset is restricted to the sum of any past service costs and the present value of refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using the year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Post-retirement medical benefits are also provided to qualifying retirees. In some cases the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans there is no funding of the benefits before retirement. These plans are recognized on the same basis as described above for the defined benefit pension plans.

The determination of the cost of the defined benefit pension plans and the other post-retirement benefit plans reflects a number of assumptions that affect the expected future benefit payments and the valuation is prepared by an independent actuary who is engaged by the Company. These assumptions include, but are not limited to: estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. The rate of return on pension plan assets is based on a projection of real long-term bond yields and an equity risk premium, which are combined with local inflation assumptions and applied to the actual asset mix of each plan. The amount of the expected return on plan assets is calculated using the expected rate of return for the year and the fair value of assets at the beginning of the year. Future salary increases are based on expected future inflation rates for the individual countries.

q) Income Taxes

Current income taxes are recognized in net earnings except when they relate to equity, which includes OCI, accumulated OCI or other reserves. Current income taxes related to equity are recognized directly in equity. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

Deferred tax is provided using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable net earnings will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized. Deferred income tax relating to items recognized directly in equity, including OCI, is recognized in equity.

Deferred tax assets and liabilities are recognized at expected tax rates in effect in the year when the asset is expected to be realized or the liability settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in net earnings when substantively enacted. Deferred tax assets and deferred tax liabilities are offset, if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

r) Non-monetary Transactions

Non-monetary transactions are measured based on fair value when there is evidence to support the fair value unless the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The acquired item is measured in this way even if the Company cannot immediately derecognize the asset given up. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up.

s) Revenue Recognition

Revenue from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured.

Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Physical exchanges are reported net for swaps of similar items, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

t) Foreign Currency

A functional currency is the currency of the primary economic environment in which the Company and subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The financial statements of Husky's subsidiaries are translated into Canadian dollars, which is the presentation and functional currency of the Company. The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the foreign exchange rate at the balance sheet date, while revenues and expenses of such subsidiaries are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are included in OCI.

Company transactions in foreign currencies are translated to the appropriate functional currency at the foreign exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

The Company applies hedge accounting to foreign currency differences arising between the functional currency of the foreign operation and the Company's functional currency, regardless of whether the net investment is held directly or through an intermediate parent. Foreign currency differences arising on the revaluation of a financial liability designated as a hedge of a net investment in a foreign operation are recognized in OCI to the extent that the hedge is effective, and are presented within equity in exchange differences on translation of foreign operations. To the extent that the hedge is ineffective, such differences are recognized in net earnings. When the hedged part of a net investment is disposed of, the relevant amount in the cumulative amount of exchange differences on translation of foreign operations is transferred to net earnings as part of the net earnings on disposal.

u) Share-Based Payments

In accordance with the Company's stock option plan and performance share units, common stock options may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted. Compensation expense is recorded in earnings as part of selling, general and administrative expenses.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for the stock options is accrued over their vesting period measured at fair value using the Black-Scholes option pricing model. The liability is revalued each reporting period until settlement to reflect changes in the fair value of the options and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

The Company's long-term incentive program consists of a Performance Share Unit Plan that provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSUs") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. A liability for expected cash payments is accrued over the vesting period of the PSUs based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount. Accrued compensation for a PSU that is forfeited is adjusted to earnings by decreasing the compensation expense in the period of forfeiture. Compensation expense is recognized in selling, general and administrative expenses.

v) Earnings per Share

The number of basic common shares outstanding is the weighted average number of common shares outstanding for each period. Shares issued during the period are included in the weighted average number of shares from the date consideration is receivable. The calculation of basic earnings per common share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding.

Except where indicated and per share amounts, all dollar amounts are in millions.

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of all dilutive potential common shares, which comprise share options granted to employees. Stock options granted to employees provide the holder with the ability to settle in cash and equity. For the purposes of the diluted earnings per share calculation, the Company must adjust the numerator for the more dilutive effect of cash-settlement versus equity-settlement despite how the stock options are accounted for in net earnings. As a result, net earnings reported based on accounting of cash-settled stock options may be adjusted for the results of equity-settlements for the purposes of determining the numerator for the diluted earnings per share calculation.

w) Government Grants

Government grants are recognized where there is reasonable assurance that the grant will be received and all attached conditions will be complied with. If a grant is received but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and released to income in equal amounts over the expected useful life of the related asset through lower depletion, depreciation and amortization.

x) Pending Accounting Standards

Financial Instruments

In November 2009, the International Accounting Standards Board (" IASB") published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. There will be no significant impact to the Company upon implementation of the issued standard.

Note 5 Cash Flows - Change in Non-cash Working Capital

	Three months ended March 31	
	2011	2010
Decrease (increase) in non-cash working capital		
Accounts receivable	**$ (48)**	$ 289
Inventories	**152**	150
Prepaid expenses	**1**	1
Accounts payable and accrued liabilities	**37**	(260)
Change in non-cash working capital	**$ 142**	$ 180
Relating to:		
Operating activities	**$ 163**	$ 321
Financing activities	**60**	54
Investing activities	**(81)**	(195)

Cash and cash equivalents at March 31, 2011 included $57 million of cash (December 31, 2010 - $185 million) and $1 million of short-term investments with maturities less than three months (December 31, 2010 - $67 million).

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 6 Exploration and Evaluation Costs

A reconciliation of the carrying amount of exploration and evaluation assets as at March 31, 2011 and December 31, 2010 is set out below.

	2011	2010
Cost at January 1 *(note 15)*	$ 472	$ 1,943
Additions	41	946
Acquisitions *(note 8)*	67	3
Transfers to oil and gas properties	(33)	(2,208)
Expensed exploration expenditures previously capitalized	(1)	(200)
Disposals	(19)	(2)
Exchange adjustments	(3)	(10)
Cost at March 31, 2011	$ 524	$ -
Cost at December 31, 2010 *(note 15)*	$ -	$ 472

The following exploration and evaluation expenses relate to activities associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Upstream segment.

	Three months ended March 31	
Exploration and Evaluation Expense Summary	2011	2010
Seismic	$ 15	$ 33
Expensed Drilling	37	4
Other	41	15
Total	$ 93	$ 52

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 7 Property, Plant and Equipment

	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
At January 1, 2010 *(note 15)*	$ 24,641	$ 1,071	$ 1,779	$ 4,430	$ 1,755	$ 33,676
Additions	1,624	8	182	296	238	2,348
Acquisitions	397	-	-	-	-	397
Transfers from exploration and evaluation	2,208	-	-	-	-	2,208
Changes in asset retirement obligations	357	7	13	16	52	445
Disposals	(15)	(17)	-	-	(17)	(49)
Exchange adjustments	(68)	-	-	(197)	-	(265)
At December 31, 2010 *(note 15)*	29,144	1,069	1,974	4,545	2,028	38,760
Additions	635	6	10	36	5	692
Acquisitions *(note 8)*	769	-	-	-	-	769
Transfers from exploration and evaluation	33	-	-	-	-	33
Transfers to assets held for sale *(note 14)*	-	(103)	-	-	-	(103)
Changes in asset retirement obligations	57	(3)	-	(4)	(4)	46
Disposals	(9)	-	-	(19)	-	(28)
Exchange adjustments	(13)	-	-	(91)	-	(104)
At March 31, 2011	30,616	969	1,984	4,467	2,029	40,065
Accumulated depreciation, depletion and impairment						
At January 1, 2010 *(note 15)*	(12,450)	(535)	(545)	(639)	(923)	(15,092)
Charge for the year	(1,487)	72	(198)	(208)	(152)	(1,973)
Disposals	8	13	-	-	13	34
Exchange adjustments	12	-	-	29	-	41
At December 31, 2010 *(note 15)*	(13,917)	(450)	(743)	(818)	(1,062)	(16,990)
Charge for the year	(431)	(10)	(25)	(55)	(21)	(542)
Transfers to assets held for sale *(note 14)*	-	44	-	-	-	44
Exchange adjustments	6	-	-	16	-	22
At March 31, 2011	(14,342)	(416)	(768)	(857)	(1,083)	(17,466)
Net book value						
At March 31, 2011	$ 16,274	$ 553	$ 1,216	$ 3,610	$ 946	$ 22,599
At December 31, 2010 *(note 15)*	$ 15,227	$ 619	$ 1,231	$ 3,727	$ 966	$ 21,770
At January 1, 2010 *(note 15)*	$ 12,191	$ 536	$ 1,234	$ 3,791	$ 832	$ 18,584

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at March 31, 2011 were $4,430 (December 31, 2010 - $4,076 million).

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 8 Acquisitions and Dispositions

ExxonMobil Acquisition

On February 4, 2011, the Company acquired oil and natural gas properties in Alberta and northeast British Columbia from ExxonMobil for consideration of $823 million before adjustments. The assets acquired are located in core areas of Husky's operations and include land, oil and gas wells, facilities, pipelines and seismic data. The fair value of the assets acquired and liabilities assumed on the date of acquisition was $818 million.

The amounts recognized on the date of acquisition for the identifiable assets acquired were:

	Amount
Exploration and evaluation assets	$ 67
Property, plant and equipment	813
Asset retirement obligations assumed	(62)
Total assets acquired	$ 818

Total cash consideration transferred for the net assets acquired was $818 million. In the period February 4, 2011 to March 31, 2011 the acquisition contributed revenue of $46 million and earnings of $12 million which are included in the consolidated net earnings for the period.

If the acquisition had occurred on January 1, 2011, management estimates that consolidated revenue would have increased by an additional $29 million and consolidated net earnings would have increased by $6 million for the three months ended March 31, 2011. In determining these amounts, management has assumed that the fair value adjustments, determined provisionally, that arose on the date of acquisition would have been the same if the acquisition had occurred on January 1, 2011.

Sale of Oil Sands Leases

On January 14, 2011, the Company completed a sales agreement to sell 23 square miles of mining leases in Alberta for cash proceeds of $200 million resulting in a gain recorded in other expenses, subject to adjustments, of approximately $177 million. The first installment of $100 million was received on January 14, 2011; the second installment of $100 million is due and receivable on January 13, 2012.

Completion of 10% Interest Sale of Husky Oil (Madura) Limited

On January 13, 2011, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP") and CNOOC Southeast Asia Limited ("CNOOCSE") both sold a 10% equity share in Husky Oil (Madura) Limited ("HOML"), a subsidiary of HOMP, to Samudra Energy Ltd. through its affiliate, SMS Development Ltd. ('SMS"). Following the completion of the sale, HOMP and CNOOCSE now each hold a 40% equity interest in HOML with the remaining 20% balance held by SMS. This sale resulted in a gain of $12 million recorded in other expenses. Husky's share of the consideration was U.S. $12.5 million in cash and a deferred purchase price for the balance of U.S. $12.5 million which bears interest at a rate of 5% and is payable to the Company from SMS's share of future distributions from HOML.

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 9 Long-term Debt

		Cdn $ Amount		US $ Denominated	
	Maturity	**March 31, 2011**	Dec. 31, 2010	**March 31, 2011**	Dec. 31, 2010
Long-term debt					
Syndicated credit facility	2012	**$ 360**	$ 380	**$ -**	$ -
6.25% notes [1]	2012	**389**	398	**400**	400
5.90% notes [2]	2014	**733**	750	**750**	750
3.75% medium-term notes [2]	2015	**303**	308	**-**	-
7.55% debentures [2]	2016	**203**	209	**200**	200
6.20% notes [2]	2017	**303**	316	**300**	300
6.15% notes	2019	**292**	298	**300**	300
7.25% notes	2019	**728**	746	**750**	750
5.00% medium-term notes	2020	**400**	400	**-**	-
6.80% notes	2037	**376**	385	**387**	387
Debt issue costs [3]		**(24)**	(26)	**-**	-
Unwound interest rate swaps		**22**	23	**-**	-
		4,085	4,187	**3,087**	3,087

(1) *A portion of the Company's debt is designated in a cash flow hedging relationship for foreign currency risk management. Refer to Note 13.*
(2) *A portion of the Company's debt is designated in a fair value hedging relationship for interest rate risk management and recorded at fair value. Refer to Note 13.*
(3) *Calculated using the effective interest rate method.*

Except where indicated and per share amounts, all dollar amounts are in millions.

Financial items for the three months ended March 31, 2011 and 2010 were as follows:

	Three months ended March 31	
	2011	2010
Foreign exchange		
Gain on translation of U.S. dollar denominated long-term debt	**$ (48)**	$ (65)
Loss on cross currency swaps	**8**	11
Loss on contribution receivable	**28**	39
Other (gains) losses	**10**	(15)
Net foreign exchange gains	**(2)**	(30)
Finance income		
Contribution receivable	**(19)**	(19)
Other	**(2)**	(4)
Finance income	**(21)**	(23)
Finance expenses		
Long-term debt	**60**	54
Contribution payable	**23**	22
	83	76
Amount capitalized [(1)]	**(17)**	(13)
	66	63
Accretion of asset retirement obligations *(note 10)*	**18**	12
Accretion of other long-term liabilities	**1**	3
Finance expenses	**85**	78
	$ 62	$ 25

[(1)] *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 6% (2010 – 7%).*

Other foreign exchange gains and losses include realized and unrealized foreign exchange gains and losses on property, plant and equipment, working capital, other balance sheet items and income statement items.

Interest coverage ratios:

	Three months ended March 31, 2011
Interest coverage ratios on long-term debt [(1) (2)]	
Net earnings	9.3
Cash flow	16.5
Interest coverage ratios on total debt [(1) (3)]	
Net earnings	9.2
Cash flow	16.3

[(1)] *Calculated for the 12 months ended for the dates shown.*
[(2)] *Interest coverage on long-term debt on an earnings basis is equal to earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized finance expense. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized finance expense. Long-term debt includes the current portion of long-term debt.*
[(3)] *Interest coverage on total debt on an earnings basis is equal to earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized finance expense. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized finance expense. Total debt includes short and long-term debt.*

Credit Facilities

The Company has a revolving syndicated credit facility which allows it to borrow up to $1.25 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a five-year committed revolving credit facility. In August 2010, Husky added a second revolving syndicated credit facility that allows the Company to borrow up to $1.5 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility was increased to $1.7 billion in the first quarter of 2011. The facility is structured as a four-year committed revolving credit facility. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the $1.25 billion syndicated credit facility.

As at March 31, 2011, the Company had borrowings of $240 million under its $1.25 billion revolving syndicated credit facility, $120 million under its bilateral credit facilities, and no borrowings under its $1.7 billion facility (December 31, 2010 - $380 million under the $1.25 billion syndicated credit facility and nil under the bilateral credit facilities or the $1.5 billion syndicated facility).

Notes and Debentures

Husky filed a debt shelf prospectus with the Alberta Securities Commissions on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009 which expired on March 26, 2011. The shelf prospectus enabled Husky to offer up to U.S. $3 billion of debt securities in the United States. During the 25-month period that the shelf prospectus was effective, debt securities could be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. In 2009, U.S. $1.5 billion of senior notes were issued under this shelf prospectus. The notes are unsecured and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1 billion of debt securities in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. On March 12, 2010, Husky issued $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020. The notes are redeemable at the option of the Company at any time, subject to a make whole provision. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As of December 31, 2010, only common shares had been issued under the prospectus. On March 18, 2011, the Company issued 12 million Cumulative Rate Reset Preferred Shares, Series 1 ("Series 1 Shares") for gross proceeds of $300 million under this shelf prospectus. (Refer to Note 11).

The 6.25% and the 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

The 5.90% and the 7.25% notes, issued in 2009, represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996. Interest is payable semi-annually.

The 6.20% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007. During 2008, the Company repurchased U.S. $63 million of the 6.80% notes. Interest is payable semi-annually.

Except where indicated and per share amounts, all dollar amounts are in millions.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

The Company's notes, debentures, credit facilities and short-term lines of credit rank equally.

The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is included in the carrying value of long-term debt.

Note 10 Asset Retirement Obligations ("ARO")

At March 31, 2011, the estimated total undiscounted inflation adjusted amount required to settle the Company's ARO was $7.9 billion (December 31, 2010 - $7.6 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using a credit-adjusted risk free rate of 6.2% (December 31, 2010 - 6.2%). Obligations related to environmental remediation and cleanup of oil and gas producing assets are included in the estimated ARO.

While the provision is based on the best estimates of future costs and the economic lives of the facilities, there is uncertainty regarding the amount and timing of incurring these costs that are not always within management's control.

Changes to the ARO for the three months ended March 31, 2011 and the year ended December 31, 2010 were as follows:

	Three months ended March 31, 2011	Year ended December 31, 2010
Asset retirement obligations at beginning of period	**$ 1,198**	$ 767
New or increased liabilities	**46**	135
Liabilities settled	**(23)**	(60)
Change in discount rate	**-**	77
Change in estimates	**-**	233
Exchange adjustment	**(2)**	(3)
Accretion [(1)]	**18**	49
Asset retirement obligations at end of period	**$ 1,237**	$ 1,198
Of which - expected to be incurred within 1 year	**$ 40**	$ 63
- expected to be incurred in more than 1 year	**1,197**	1,135

(1) *Accretion is included in finance expenses.*

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 11 Share Capital

Common Shares

Changes to issued shared capital were as follows:

	Number of Shares	Amount
January 1, 2010	849,860,935	$ 3,585
Common shares issued, net of share issue costs	40,816,326	988
Options exercised	31,534	1
December 31, 2010 and March 31, 2011	**890,708,795**	**$ 4,574**

Amendments to Common Share Terms

In the Special Meeting of Shareholders held on February 28, 2011, Husky's shareholders approved amendments to the common share terms, which provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

Preferred Shares

On March 18, 2011, Husky issued 12 million Series 1 Shares at a price of $25.00 per share for aggregate gross proceeds of $300 million. Net proceeds after share issue costs were $291 million. The Series 1 Shares were offered by way of a prospectus supplement under the short form base shelf prospectus dated November 26, 2010.

The Series 1 Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.45% annually for the initial period ending March 31, 2016. Thereafter, the dividend rate will be reset every five years at a rate equal to the 5-year Government of Canada bond yield plus 1.73%. Holders of Series 1 Shares will have the right, at their option, to convert their shares into Cumulative Rate Reset First Preferred Shares, Series 2 (the "Series 2 Shares"), subject to certain conditions, on March 31, 2016 and on March 31 every five years thereafter. Holders of the Series 2 Shares will be entitled to receive cumulative quarterly floating rate dividends at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%.

In the event of liquidation, dissolution or winding-up of the Company, the holders of the Series 1 Shares will be entitled to receive $25 per share as well as all accrued unpaid dividends before any amounts will be paid or any assets of the Company will be distributed to the holders of any other shares ranking junior to the Series 1 Shares. The holders of the Series 1 Shares will not be entitled to share in any further distribution of the assets of the Company.

Share-Based Payments

The Company has two types of options: a tandem plan and a tandem performance based plan. The tandem plan provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the date of the award. For options granted up to 2009, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. For options granted after 2009, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares for the five trading days following the surrender date and the exercise price of the option.

Except where indicated and per share amounts, all dollar amounts are in millions.

Under the terms of the stock option plan, the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year. Performance options granted may vest in up to one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking. Stock compensation expense related to the performance options is accrued based on the price of the common shares at the end of the period and the anticipated performance factor. This expense is recognized over the three-year vesting period of the performance options. Performance options are no longer granted and the last grant was on May 6, 2010.

The fair value of the share options is estimated at each reporting date using the Black-Scholes option pricing model, taking into account the terms and conditions upon which the share options are granted and for the performance based options, the current likelihood of achieving the specified target.

The carrying amount of the liability relating to the tandem plan at March 31, 2011 was $22 million (December 31, 2010 - $14 million). The carrying amount of the liability relating to the tandem performance based plan at March 31, 2011 was nil (December 31, 2010 - $3 million). The total expense recognized for the tandem plan and the tandem performance based plan during the first three months of 2011 was $5 million (March 31, 2010 – recovery of $11 million).

The following options to purchase common shares have been awarded to officers and certain other employees:

	Three months ended March 31					
	2011			2010		
	Number of Options *(thousands)*	Weighted Average Exercise Prices		Number of Options *(thousands)*	Weighted Average Exercise Prices	
Outstanding, beginning of year	29,541	$	37.04	28,399	$	40.78
Granted	65	$	28.96	-	$	-
Surrendered for cash	-	$	-	(5)	$	16.41
Forfeited	(1,580)	$	36.96	(489)	$	40.61
Outstanding at March 31	**28,026**	**$**	**37.03**	27,905	$	40.79
Options exercisable at March 31	**16,808**	**$**	**41.37**	15,038	$	41.08

	March 31, 2011						
	Outstanding Options				Options Exercisable		
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices		Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices	
$25.41 - $29.99	9,139	$	28.09	4	102	$	29.81
$30.00 - $34.99	1,222	$	31.23	3	537	$	31.14
$35.00 - $39.99	727	$	38.21	1	727	$	38.21
$40.00 - $42.99	13,832	$	41.60	1	13,832	$	41.60
$43.00 - $45.02	3,106	$	45.02	2	1,610	$	45.02
	28,026	$	37.03	2	16,808	$	41.37

Except where indicated and per share amounts, all dollar amounts are in millions.

The following tables list the inputs to the Black-Scholes option pricing model of the two plans as at the dates indicated:

	March 31, 2011	
	Tandem Options	Tandem Performance Based Options
Dividend per option	$ 1.28	$ 1.28
Range of expected volatilities used *(percent)*	0.0 – 37.9	0.0 – 37.8
Range of risk-free interest rates used *(percent)*	0.9 – 2.8	0.9 – 2.2
Expected life of share options from vesting date *(years)*	1.6	1.6
Fair value weighted average exercise price	$ 37.06	$ 41.20

	March 31, 2010	
	Tandem Options	Tandem Performance Based Options
Dividend per option	$ 1.06	$ 1.06
Range of expected volatilities used *(percent)*	15.8 – 45.3	16.0 – 45.3
Range of risk-free interest rates used *(percent)*	0.2 – 2.0	0.2 – 2.0
Expected life of share options from vesting date *(years)*	1.6	1.6
Fair value weighted average exercise price	$ 40.69	$ 41.33

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units ("PSU")

In February 2010, the Compensation Committee of the Board of Directors of Husky established the Performance Share Unit Plan for certain officers and employees of the Company. A PSU is a time-vested award entitling participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. During 2011, 15,000 PSUs were granted to senior management and no PSUs were forfeited. As at March 31, 2011, 235,000 PSUs (December 31, 2010 - 220,000 PSUs) were outstanding.

Note 12 Commitments and Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and deferred income taxes.

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 13 Financial Instruments and Risk Factors

Risk Management Overview

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

Husky is exposed to risk factors associated with operating in developing countries, political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Fair Value of Financial Instruments

The Company's financial instruments as at March 31, 2011 included cash and cash equivalents, accounts receivable, contribution receivable, bank operating loans, accounts payable and accrued liabilities, contribution payable and long-term debt.

At March 31, 2011, the carrying value of the contribution receivable and contribution payable was $1.2 billion (December 31, 2010 - $1.3 billion) and $1.4 billion (December 31, 2010 - $1.4 billion) respectively.

The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Fair values of the derivatives are based on quoted market prices where available. The fair values of swaps and forward contracts are based on forward market prices. If a forward price is not available for a commodity based forward contract, a forward price is estimated using an existing forward price adjusted for quality or location. All of the Company's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2. During the periods ending March 31, 2011 and December 31, 2010, there were no transfers into or out of Level 2 fair value measurements.

The financial instruments recorded at fair value on the balance sheet were as follows:

	At Mar. 31, 2011	At Dec. 31, 2010	At Jan.1, 2010
Financial assets at fair value			
Trading derivatives	**$ 35**	$ 34	$ 22
Financial liabilities at fair value			
Trading derivatives	**$ 28**	$ 12	$ 16

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The fair value of long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risk, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

Except where indicated and per share amounts, all dollar amounts are in millions.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The Company's results will also be impacted by a decrease in the price of crude oil. The Company holds crude oil inventories that are feedstock or part of the in-process inventories at its refineries. These inventories are subject to a lower of cost or net realizable value test on a monthly basis and the Company is exposed to declining crude prices.

The Company's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. The majority of the Company's expenditures are in Canadian dollars.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company has entered into cash flow hedges using cross currency debt swaps. In addition, a portion of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation which has a U.S. dollar functional currency and the unrealized foreign exchange gain is recorded in OCI.

To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. The Company's objectives, processes and policies for managing market risk have not changed from the previous year.

Commodity Price Risk Management

Natural Gas Contracts

At March 31, 2011, the Company had the following third party physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	17,816	$ -
Physical sale contracts	(17,433)	$ 1

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of less than $1 million (March 31, 2010 – unrealized loss of $1 million) has been recorded in other expenses in the Condensed Interim Consolidated Statements of Income and Condensed Interim Consolidated Statements of Other Comprehensive Income.

Natural Gas Storage Contracts

At March 31, 2011, the Company had the following third party physical purchase and sale natural gas storage contracts:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	3,598	$ -
Physical sale contracts	(18,282)	$ -

Except where indicated and per share amounts, all dollar amounts are in millions.

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable respectively. The change in the fair value of these contracts resulted in an unrealized loss of $31 million (March 31, 2010 – unrealized gain of $12 million) which has been recorded in other expenses.

Natural gas inventories held in storage relating to these contracts are recorded at fair value. At March 31, 2011, the fair value of the inventories was $59 million (December 31, 2010 - $131 million). The cumulative fair value change on this inventory as of March 31, 2011 was an unrealized gain of $4 million (March 31, 2010 – unrealized gain of $28 million). The change in the fair value of inventory resulted in an unrealized gain of $10 million (March 31, 2010 - unrealized loss of $41 million) which has been recorded in other expenses.

Oil Contracts

The Company designated certain crude oil purchase and sale contracts as fair value hedges against the changes in the fair value of the inventory held in storage. The assessment of effectiveness for the fair value hedges excludes changes between current market prices and market prices on the settlement date in the future.

At March 31, 2011, the Company had the following third party crude oil purchase and sale contracts which have been recorded as a fair value hedge:

	Volumes *(bbls)*	Fair Value
Physical purchase contracts	81,716	$ (1)

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized gain of $1 million (March 31, 2010 - unrealized loss of $3 million) has been recorded in earnings. The crude oil inventory held in storage is recorded at fair value. At March 31, 2011, the fair value of the inventory was $8 million, resulting in an unrealized loss of $1 million (March 31, 2010 - unrealized loss of less than $1 million) recorded in earnings.

The Company has entered into contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at March 31, 2011, a loss related to these contracts of $7 million (March 31, 2010 - loss of $1 million) was recorded in other expenses.

The Company enters into certain crude oil purchase and sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company had the following crude oil contracts as at March 31, 2011:

	Volumes *(mbbls)*	Fair Value
Physical purchase contracts	1,600	$ (170)
Physical sale contracts	(1,600)	$ 169

These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At March 31, 2011, a resulting unrealized gain of $7 million (March 31, 2010 - nil) was recorded in other expenses. A portion of the crude oil inventory is sold to third parties. This inventory is considered held for realizing short term trading margins and as such, has been recorded at its fair value. At March 31, 2011, the fair value of inventory was $155 million, resulting in an unrealized gain of $4 million (March 31, 2010 - nil) recorded in other expenses.

Where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are recorded in revenue and cost of sales when physical delivery occurs.

Except where indicated and per share amounts, all dollar amounts are in millions.

Interest Rate Risk Management

At March 31, 2011, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates with the following terms:

Notional Amount			Swap Maturity	Swap Rate *(percent)*	Fair Value	
U.S.	$	200	November 15, 2016	LIBOR + 417 bps	$	9
U.S.	$	300	September 15, 2017	LIBOR + 264 bps	$	11
U.S.	$	150	June 15, 2014	LIBOR + 350 bps	$	4
Cdn.	$	300	March 12, 2015	CDOR + 0.83%	$	3

During 2011, these swaps resulted in a reduction to finance expense amounting to $5 million (March 31, 2010 – reduction of $4 million). The amortization of previous interest rate swap terminations resulted in an addition to finance expense of $1 million (March 31, 2010 - addition of $1 million).

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At March 31, 2011, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount			Canadian Equivalent		Swap Maturity	Interest Rate *(percent)*	Fair Value	
6.25% notes	U.S.	$	150	$	211	June 15, 2012	7.41	$	(79)
6.25% notes	U.S.	$	75	$	89	June 15, 2012	5.65	$	(19)
6.25% notes	U.S.	$	50	$	59	June 15, 2012	5.67	$	(12)
6.25% notes	U.S.	$	75	$	88	June 15, 2012	5.61	$	(17)

These contracts have been recorded at fair value in other long-term liabilities. The portion of the fair value of the derivative related to foreign exchange has been recorded in earnings to offset the foreign exchange on the translation of the underlying debt and the remaining gain has been included in OCI. For the three months ended March 31, 2011, the unrealized foreign exchange gain of $14 million (March 31, 2010 - unrealized gain of $4 million), net of tax of $4 million (March 31, 2010 - $2 million) was recorded in OCI. At March 31, 2011, the balance in Other Reserves related to the derivatives designated as a cash flow hedge was $14 million (December 31, 2010 - $2 million), net of tax of $4 million (December 31, 2010 – less than $1 million). For the three months ended March 31, 2011, the Company recognized a foreign exchange loss of $8 million (March 31, 2010 - loss of $11 million) on the cross currency debt swaps.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the three months ended March 31, 2011, the impact of these contracts was a gain of $7 million (March 31, 2010 - gain of $8 million) recorded in foreign exchange loss.

As at March 31, 2011, the Company has designated U.S. $987 million (December 31, 2010 – U.S. $987 million) of its U.S. debt as a hedge of the Company's net investments in the U.S. refining operations, which is considered a foreign functional currency entity. In 2011, the unrealized gain arising from the translation of the debt was $19 million (March 31, 2010 – unrealized gain of $26 million), net of provisions for income taxes of $3 million (March 31, 2010 - $4 million), which was recorded in OCI.

Except where indicated and per share amounts, all dollar amounts are in millions.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's Upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company has the following available credit facilities as at March 31, 2011:

Credit Facilities	Available	Unused
Operating facilities	$ 414	$ 297
Syndicated bank facilities	2,950	2,710
Bilateral credit facilities	150	30
Total	$ 3,514	$ 3,037

In addition to the credit facilities listed above, the Company has unused capacity under the debt shelf prospectus filed in Canada of $300 million, and unused capacity under the universal short form base shelf prospectus filed in Canada of $2.4 billion, the availability of which is dependent on market conditions. The Company believes it has sufficient funding through the use of these facilities to meet its future borrowing requirements.

The Company's contribution payable to the joint arrangement with BP is payable between March 31, 2011 and December 31, 2015, with the final balance due and payable by December 31, 2015.

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. The Company's accounts receivables are broad based with customers in the energy industry, midstream and end user segment and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial reassurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company did not have any customers that constituted more than 10% of total sales and operating revenues during the first quarter of 2011 or 2010.

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure.

Note 14 Related Party Transactions

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors. These notes were offered through an existing base shelf prospectus, which was filed with the U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5- and 10-year tranches respectively. Subsequent to this offering, U.S. $65 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At March 31, 2011, the senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, Husky issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions. These transactions occur in the normal course of business and have been measured at the fair value. For the three months ended March 31, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $26 million (March 31, 2010 - $28 million). In 2011, the Company and TACLP agreed to sell the Meridian cogeneration facility to a related party. The consideration for Husky's share of the cogeneration facility is $61 million. The carrying value of Husky's interest in the cogeneration facility has been reclassified to current asset held for sale as at March 31, 2011.

Note 15 First-time Adoption of International Financial Reporting Standards

As discussed in Note 3, these are the Company's first condensed interim consolidated financial statements for the period covered by the first annual consolidated financial statements to be prepared in accordance with IFRS.

The accounting policies in Note 4 have been applied in preparing the condensed interim consolidated financial statements for the first three months ended March 31, 2011, the comparative information for the three months ended March 31, 2010, the balance sheet for the year ended December 31, 2010 and the preparation of an opening IFRS balance sheet on the transition date, January 1, 2010.

In preparing the condensed interim consolidated financial statements for the three months ended March 31, 2011, comparative information for the three months ended March 31, 2010 and financial statements for the year ended December 31, 2010, have been adjusted from the amounts reported previously in the financial statements prepared in accordance with Canadian GAAP.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables.

Key First-Time Adoption Exemptions Applied

IFRS 1 *First-Time Adoption of International Financial Reporting Standards* allows first-time adopters certain exemptions from retrospective application of certain IFRS.

The Company has applied the following exemptions:

- Certain oil and gas assets in property, plant and equipment on the balance sheet were recognized and measured on a full cost basis in accordance with Canadian GAAP. The Company has elected to measure its Canadian properties at the amount determined under Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proved developed reserve volumes as at January 1, 2010. Associated decommissioning assets were also measured at their carrying value under Canadian GAAP while all decommissioning liabilities were measured using a consistent credit-adjusted risk free rate, with a corresponding adjustment recorded to opening retained earnings. The Company has elected not to apply the IFRS 1 full cost exemption to its International upstream properties.

- IFRS 3 *Business Combinations* has not been applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.
- The Company has elected to apply IAS 23 *Borrowing Costs* with an effective date of January 1, 2003 which requires mandatory capitalization of borrowing costs directly attributable to the acquisition, construction or production of qualifying assets. De-recognition of previously capitalized borrowing costs in accordance with Canadian GAAP did not have a material impact to the Company.
- The Company has recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits in retained earnings as at January 1, 2010.
- Cumulative currency translation differences for all foreign operations are deemed to be zero as at January 1, 2010. Accordingly, all cumulative foreign exchange gains and losses in the Company's cumulative foreign currency translation account have been recognized in retained earnings at January 1, 2010.
- IFRS 2 *Share-based Payment* has not been applied to equity instruments related to stock-based compensation arrangements that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share-based payment transactions, the Company has not applied IFRS 2 to liabilities that were settled before January 1, 2010.
- The Company has not reassessed any arrangements to determine whether they contain a lease if they have already been assessed under Canadian GAAP. Additionally, any arrangements that have not been assessed under Canadian GAAP have been assessed under IFRIC 4 *Determining Whether an Arrangement Contains a Lease* based on terms and conditions existing at January 1, 2010.

Except where indicated and per share amounts, all dollar amounts are in millions.

Reconciliation of Equity at January 1, 2010 (Date of Transition to IFRS)

	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	$ 392	$ -	$ 392
Accounts receivable	987	-	987
Inventories	1,520	-	1,520
Prepaid expenses	12	-	12
	2,911	-	2,911
Exploration and evaluation assets *(notes a, d, j)*	-	1,943	1,943
Property, plant and equipment *(notes a, c, d, e, f, h)*	21,288	(2,704)	18,584
Goodwill	689	-	689
Contribution receivable	1,313	-	1,313
Other assets *(note b)*	94	(26)	68
	$ 26,295	$ (787)	$ 25,508
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	$ 1,915	$ 26	$ 1,941
Income taxes payable	270	-	270
Asset retirement obligations *(note f)*	29	-	29
	2,214	26	2,240
Long-term debt	3,229	-	3,229
Other long-term financial liabilities	96	-	96
Other long-term liabilities *(notes b, c, g, i)*	147	137	284
Contribution payable	1,500	-	1,500
Deferred tax liabilities *(note l)*	3,932	(227)	3,705
Asset retirement obligation *(notes d, f)*	764	(26)	738
	$ 11,882	$ (90)	$ 11,792
Shareholders' equity			
Common shares	3,585	-	3,585
Retained earnings *(note m)*	10,832	(733)	10,099
Other reserves *(note d)*	(4)	36	32
	14,413	(697)	13,716
	$ 26,295	$ (787)	$ 25,508

Except where indicated and per share amounts, all dollar amounts are in millions.

Reconciliation of Equity at March 31, 2010

	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	$ 502	$ -	$ 502
Accounts receivable	1,304	-	1,304
Inventories	1,596	-	1,596
Prepaid expenses	13	-	13
	3,415	-	3,415
Exploration and evaluation assets *(notes a, d, j)*	-	2,188	2,188
Property, plant and equipment *(notes a, c, d, e, f, h)*	21,423	(2,971)	18,452
Goodwill	674	-	674
Contribution receivable	1,293	-	1,293
Other assets, including derivatives *(notes b, d)*	143	(25)	118
	$ 26,948	$ (808)	$ 26,140
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	$ 2,179	$ 22	$ 2,201
Income taxes payable	-	-	-
Asset retirement obligations *(note f)*	13	-	13
	2,192	22	2,214
Long-term debt	3,837	-	3,837
Other long-term financial liabilities	99	-	99
Other long-term liabilities *(notes b, c, g, i)*	145	125	270
Contribution payable	1,477	-	1,477
Deferred tax liabilities *(note l)*	3,958	(212)	3,746
Asset retirement obligation *(notes d, f)*	782	(28)	754
	$ 12,490	$ (93)	$ 12,397
Shareholders' equity			
Common shares	3,585	-	3,585
Retained earnings *(note m)*	10,922	(710)	10,212
Other reserves *(notes b, d)*	(49)	(5)	(54)
	14,458	(715)	13,743
	$ 26,948	$ (808)	$ 26,140

Except where indicated and per share amounts, all dollar amounts are in millions.

Reconciliation of Equity at December 31, 2010

	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	$ 252	$ -	$ 252
Accounts receivable	1,529	-	1,529
Inventories	1,935	-	1,935
Prepaid expenses	34	-	34
	3,750	-	3,750
Exploration and evaluation assets *(notes a, d, j)*	-	472	472
Property, plant and equipment *(notes a, c, d, e, f, h, j)*	23,299	(1,529)	21,770
Goodwill	663	-	663
Contribution receivable	1,284	-	1,284
Other assets, including derivatives *(note b)*	137	(26)	111
	$ 29,133	$ (1,083)	$ 28,050
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	$ 2,494	$ 12	$ 2,506
Income taxes payable	-	-	-
Asset retirement obligations *(note f)*	63	-	63
	2,557	12	2,569
Long-term debt	4,187	-	4,187
Other long-term financial liabilities	102	-	102
Other long-term liabilities *(notes b, c, g, i)*	165	124	289
Contribution payable	1,427	-	1,427
Deferred tax liabilities *(note l)*	4,115	(348)	3,767
Asset retirement obligation *(notes d, f)*	1,087	48	1,135
	$ 13,640	$ (164)	$ 13,476
Shareholders' equity			
Common shares	4,574	-	4,574
Retained earnings *(note m)*	10,985	(959)	10,026
Other reserves *(notes b, d)*	(66)	40	(26)
	15,493	(919)	14,574
	$ 29,133	$ (1,083)	$ 28,050

Except where indicated and per share amounts, all dollar amounts are in millions.

Reconciliation of Total Comprehensive Income for the Three Months ended March 31, 2010

	Canadian GAAP	Effects of Transition to IFRS	IFRS
Gross revenues *(notes d, k)*	$ 4,757	$ (264)	$ 4,493
Royalties	(286)	-	(286)
Revenues, net of royalties	4,471	(264)	4,207
Costs and expenses			
Purchase of crude oil and products *(notes d, k)*	2,807	(263)	2,544
Production and operating expenses	572	-	572
Selling, general and administrative expenses *(notes d, g)*	59	(12)	47
Depletion, depreciation and amortization *(notes a, d, e, h)*	485	(36)	449
Exploration and evaluation expenses *(notes a, d)*	-	52	52
Other – net (*notes f, i)*	33	(6)	27
	3,956	(265)	3,691
Earnings from operating activities	515	1	516
Financial items			
Net foreign exchange gains (losses) *(note d)*	1	29	30
Finance income	23	-	23
Finance expenses *(notes d, f, i, j)*	(85)	7	(78)
	(61)	36	(25)
Earnings before income taxes	454	37	491
Provisions for (recovery of) income taxes			
Current	78	-	78
Deferred *(note l)*	31	14	45
	109	14	123
Net earnings	345	23	368
Other comprehensive income (loss)			
Derivatives designated as cash flow hedges, net of tax	4	-	4
Actuarial gains (losses) on pension plans, net of tax *(note b)*	-	3	3
Exchange differences on translation of foreign operations, *(note d)*	(75)	(43)	(118)
Hedge of net investment, net of tax *(note d)*	26	(1)	25
Total comprehensive income (loss for the year)	$ 300	$ (18)	$ 282

Except where indicated and per share amounts, all dollar amounts are in millions.

Reconciliation of Total Comprehensive Income for the Year ended December 31, 2010

	Canadian GAAP	Effects of Transition to IFRS	IFRS
Gross revenues *(notes d, k)*	$ 19,156	$ (854)	$ 18,302
Royalties	(978)	-	(978)
Revenues, net of royalties	18,178	(854)	17,324
Costs and expenses			
Purchase of crude oil and products *(notes d, k)*	11,651	(854)	10,797
Production and operating expenses	2,309	-	2,309
Selling, general and administrative expenses *(notes d, g)*	305	(14)	291
Depletion, depreciation and amortization *(notes a, d, e, h)*	2,073	(81)	1,992
Exploration and evaluation expenses *(notes a, d)*	-	438	438
Other – net (*notes h, i)*	23	(38)	(15)
	16,361	(549)	15,812
Earnings from operating activities	1,817	(305)	1,512
Financial items			
Net foreign exchange gains (losses) *(note d)*	2	(51)	(49)
Finance income	79	-	79
Finance expenses *(notes d, f, i, j)*	(340)	15	(325)
	(259)	(36)	(295)
Earnings before income taxes	1,558	(341)	1,217
Provisions for (recovery of) income taxes			
Current	188	-	188
Deferred *(note l)*	197	(115)	82
	385	(115)	270
Net earnings	1,173	(226)	947
Other comprehensive income (loss)			
Derivatives designated as cash flow hedges, net of tax	6	-	6
Actuarial gains (losses) on pension plans, net of tax *(note b)*	-	(14)	(14)
Exchange differences on translation of foreign operations, net of tax *(note d)*	(112)	21	(91)
Hedge of net investment, net of tax *(note d)*	44	(3)	41
Total comprehensive income (loss for the year)	$ 1,111	$ (222)	$ 889

Notes to the Reconciliations of Equity and Total Comprehensive Income from Canadian GAAP to IFRS

a) IFRS 6 Adjustments – Exploration for and Evaluation of Mineral Resources

i) Accounting for Oil and Gas Properties

Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized and accumulated within cost centres on a country-by-country basis. Depletion of oil and gas properties was calculated using the unit-of-production method based on proved oil and gas reserves for each cost centre. Under IFRS, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, are expensed as incurred. After the legal right to explore is acquired, land acquisition costs and expenditures directly associated with exploratory wells are capitalized as exploration and evaluation assets. Geological and geophysical and other exploration costs are immediately recognized in exploration and evaluation expenses. Land acquisition costs remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Land acquisition costs associated with successful exploration are reclassified into property, plant and equipment. Exploratory wells remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be written-off to exploration and evaluation expenses. Wells that result in commercial quantities of reserves remain capitalized and reclassified into property, plant, and equipment.

The Company has elected to apply the IFRS 1 exemption for its Canadian oil and gas assets. Development costs at January 1, 2010 were deemed to be $8,704 million, representing the Canadian upstream full cost pool balance under previous GAAP. For international cost centres where the Company has elected not to apply the IFRS 1 deemed cost exemption, previously capitalized costs related to unsuccessful exploration drilling, geological and geophysical expenditures, exploratory seismic and lease rental expenses have been recorded as a reduction to property, plant and equipment and opening retained earnings upon adoption of IFRS 6. As a result, inception to January 1, 2010 exploration activities that would have been expensed under IFRS totalled $516 million. For the three months ended March 31, 2010, the Company reduced net property, plant, and equipment by $49 million, in accordance with IFRS 6, and recognized these amounts as exploration and evaluation expenses for all cost centres. For the year ended December 31, 2010, exploration and evaluation expenses totalled $438 million.

ii) Depletion Expense

The application of IFRS oil and gas accounting policies resulted in differences in the carrying costs subject to depletion under IFRS as compared to full cost accounting. Additionally, differences in depletion arose from the determination of depletion at the field level under IFRS versus a country level under full cost accounting. For the three months ended March 31, 2010, the Company has recognized reduced depletion, depreciation and amortization of $38 million under IFRS when compared to full cost accounting for international oil and gas properties and increased depletion, depreciation and amortization of $11 million under IFRS when compared to full cost accounting for Canadian oil and gas properties. For the year ended December 31, 2010, the Company has recognized reduced depletion, depreciation and amortization of $173 million under IFRS when compared to full cost accounting for International oil and gas properties and increased depletion, depreciation and amortization of $129 million under IFRS when compared to full cost accounting for Canadian oil and gas properties. This net reduction in depletion, depreciation and amortization can be explained in part due to the opening adjustment to international oil and gas assets as described above.

iii) Exploration and Evaluation Assets

Under IFRS 6, management has assessed the classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment and classification of the costs incurred. For capitalized costs associated with exploratory activities, the Company has presented these costs separately on the balance sheet. Costs totalling $1,939 million as at January 1, 2010, $2,196 million as at March 31, 2010 and $477 million as at December 31, 2010 were reclassified from property, plant, and equipment to exploration and evaluation assets.

Except where indicated and per share amounts, all dollar amounts are in millions.

The total impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Increase in exploration and evaluation expenses	$ 438	$ 49
Decrease in depletion, depreciation and amortization	(44)	(27)
Adjustment before income taxes	$ 394	$ 22

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in exploration and evaluation assets	$ (1,939)	$ (2,196)	$ (477)
Decrease in property, plant and equipment	2,455	2,734	1,387
Decrease in retained earnings	$ 516	$ 538	$ 910

b) IAS 19 Adjustments – Employee Benefits

i) Unamortized net actuarial loss and past service costs

IAS 19 allows the Company to recognize the unamortized net actuarial loss and past service costs for its defined benefit pension plans immediately in OCI. Canadian GAAP requires amortization of these losses and costs to net earnings over the estimated average remaining service life, with disclosure of the total cumulative unrecognized amount in the notes to the consolidated financial statements. Upon adoption of IAS 19 at January 1, 2010, the Company recognized a decrease of $65 million and an increase of $12 million in opening retained earnings related to the Company's cumulative unrecognized actuarial losses and past service cost recoveries, respectively. Additional OCI of $3 million was recorded in OCI representing unamortized net actuarial gain for the three months ended March 31, 2010. For the year ended December 31, 2010, a charge to OCI of $20 million (before taxes of $6 million) was recorded in OCI representing unamortized net actuarial loss for the year.

The total impact of this change decreased/(increased) retained earnings and other reserves as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease/(increase) in other comprehensive income, before income taxes	$ 20	$ (3)
Adjustment before income taxes	$ 20	$ (3)

Except where indicated and per share amounts, all dollar amounts are in millions.

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Decrease in other assets	$ 26	$ 26	$ 26
Increase in other long-term liabilities	27	24	47
Decrease in retained earnings	53	53	53
Decrease/(increase) in other reserves	$ -	$ (3)	$ 20

c) IAS 20 Adjustments – Government Grants

Under IAS 20, government grants are recognized when there is reasonable assurance that the entity will comply with the conditions attached to them and the grants will be received. Under Canadian GAAP, government grants are recognized when received. The Company received government grants for the expansion of its ethanol plants which are subject to repayments dependent on the profitability of its operations as assessed annually until 2015. The Company does not have reasonable assurance of the amounts repayable on the grant until the repayment requirements are fulfilled. At January 1, 2010, the Company de-recognized these government grants until reasonable assurance of the measurement of repayments is determinable which increased property, plant, and equipment and other long-term liabilities by $15 million as at January 1, 2010, March 31, 2010 and December 31, 2010. The reclassification from property, plant, and equipment would have resulted in increased depletion, depreciation and amortization of $2 million from inception to January 1, 2010; this amount was recorded as a reduction of property, plant, and equipment and opening retained earnings. For the three months ended March 31, 2010 and the year ended December 31, 2010 the reclassification of government grants increased depletion, depreciation and amortization by less than $1 million.

d) IAS 21 Adjustments – The Effects of Changes in Foreign Exchange Rates

Under IFRS, the functional currency of an entity is determined by focusing on the primary economic environment in which it operates and less precedence is placed on factors regarding the financing from and operational involvement of the reporting entity which consolidates the entity in its financial statements. Under Canadian GAAP, equal precedence is placed on all factors. The effect of this change to IFRS resulted in two entities having a different functional currency than the Company's functional currency. As such, the translation of the results and balance sheet of the foreign operations into the Company's presentation currency requires a translation of all assets and liabilities at the closing rate at each reporting date with all resulting foreign exchange gains or losses recognized in OCI. Revenues and expenses of foreign operations are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions with foreign exchange differences recognized in OCI. The retrospective application of IAS 21 resulted in a cumulative foreign currency exchange loss on revaluation of $29 million as at January 1, 2010 which was recognized in other reserves prior to applying the IFRS 1 exemption.

The Company elected to utilize the IFRS 1 exemption to deem all foreign currency translation differences of $36 million that arose prior to the date of transition with respect to all foreign operations to be nil at the date of transition. The Company reversed the balance of exchange differences on translation of foreign operations within other reserves and recorded a decrease to opening retained earnings of $65 million.

For the three months ended March 31, 2010, net foreign exchange gains of $25 million and losses of $43 million were attributed to the above entities that were assessed as having a different functional currency than the Company's functional currency under IFRS; these amounts were recorded from net earnings and OCI respectively.

For the year ended December 31, 2010, net foreign exchange losses of $53 million and gain of $21 million were attributed to the above mentioned entities that were assessed as having a different functional currency than the Company's functional currency under IFRS; these amounts were recorded from net earnings OCI respectively.

For the three months ended March 31, 2010, the Company reclassified $1 million of foreign exchange gains on translation of its foreign operations from other reserves to net earnings under Canadian GAAP. Under IFRS, this reclassification is not required until the foreign operation is partially or fully disposed. The Company recorded increased net foreign exchange gains and reduced OCI of $1 million under IFRS for the three months ended March 31, 2010.

Except where indicated and per share amounts, all dollar amounts are in millions.

For the year ended December 31, 2010, the Company reclassified $3 million of foreign exchange gains on translation of its foreign operations from other reserves to net earnings under Canadian GAAP. Under IFRS, this reclassification is not required until the foreign operation is partially or fully disposed. The Company recorded increased net foreign exchange gains and reduced OCI of $3 million under IFRS for the year ended December 31, 2010.

The impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in gross revenues	$ 2	$ 3
Decrease in purchases of crude oil and other products	(2)	(2)
Decrease in selling, general and administrative expenses	(1)	(1)
Decrease in depletion, depreciation and amortization	(1)	-
Increase in exploration and evaluation expenses	-	3
Decrease/(increase) in net foreign exchange gains	51	(29)
Increase in finance expenses	1	-
Adjustment before income taxes	$ 50	$ (26)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Decrease in exploration and evaluation assets	$ 39	$ 60	$ 11
Decrease/(increase) in property, plant and equipment	(4)	(7)	58
Increase in other assets	-	(1)	-
Increase in accounts payable and other accrued liabilities	3	4	-
Decrease in asset retirement obligations	(9)	(10)	(8)
Increase in deferred tax liability	-	1	-
Decrease/(increase) in retained earnings	65	39	115
Decrease/(increase) in other reserves	$ (36)	$ 8	$ (54)

e) IAS 36 Adjustments – Impairment of Assets

Under Canadian GAAP, impairment of long-lived assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition under IFRS, where a long-lived asset does not generate largely independent cash inflows, the Company is required to perform its test at a cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

With the adoption of IAS 36, the Company recorded impairments on its ethanol plants decreasing property, plant, and equipment by $91 million as at January 1, 2010 based on their recoverable amounts using a fair value less cost to sell valuation based on a 39 year cash flow projection discounted at a pre-tax rate of 11%. For the three months ended

Except where indicated and per share amounts, all dollar amounts are in millions.

March 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation, and amortization of $1 million. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $3 million.

The adoption of IAS 36 and application of the full cost exemption also resulted in an impairment of the carrying value of oil and gas properties in the East Central Alberta and Foothills West districts decreasing property, plant, and equipment by $66 million as at January 1, 2010. The recoverable amounts were based on fair value less cost to sell valuations using proved plus probable reserve life discounted at pre-tax rates ranging from 13% to 14%. For the three months ended March 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $2 million. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $7 million.

The impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in depletion, depreciation and amortization	$ (10)	$ (3)
Adjustment before income taxes	$ (10)	$ (3)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Decrease in property, plant and equipment	$ 157	$ 154	$ 147
Decrease in retained earnings	$ 157	$ 154	$ 147

f) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets

i) Asset Retirement Obligations ("ARO")

Consistent with IFRS, decommissioning provisions (ARO) have been previously measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under IAS 37, asset retirement obligations will continue to be discounted using a credit-adjusted risk free rate, however, the liability is required to be re-measured based on changes in estimates including discount rates.

For asset retirement obligations associated with Canadian oil and gas properties where the IFRS 1 exemption was utilized, the Company re-measured ARO as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. The carrying values of Canadian oil and gas assets associated with ARO under Canadian GAAP were not adjusted on transition to IFRS. This resulted in a decrease in ARO and an increase in opening retained earnings of $13 million as at January 1, 2010. Accordingly for the three months ended March 31, 2010, the Company recorded reduced accretion of $1 million under IFRS. For the year ended December 31, 2010, the Company recorded reduced accretion of $3 million under IFRS. At December 31, 2010, the Company re-measured the ARO based on a change in the discount rate from 6.4% to 6.2% which increased property, plant, and equipment and ARO by $66 million.

Except where indicated and per share amounts, all dollar amounts are in millions.

The total impact of this change to ARO of Canadian oil and gas assets subject to the IFRS 1 exemption decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in finance expenses	$ (3)	$ (1)
Adjustment before income taxes	$ (3)	$ (1)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in property, plant and equipment	$ -	$ -	$ (66)
Decrease/(increase) in asset retirement obligations	(13)	(14)	50
Increase in retained earnings	$ (13)	$ (14)	$ (16)

For asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets that were not subject to the IFRS 1 exemption, a retrospective application of IAS 37 was performed. This resulted in an increase in net property, plant, and equipment of $38 million as at January 1, 2010 and March 31, 2010, and an incremental increase of $11 million for the year ended December 31, 2010. Asset retirement obligations decreased by $4 million as at January 1, 2010 and increased by an incremental $10 million for the year ended December 31, 2010. For the three months ended March 31, 2010, the Company recorded reduced accretion of less than $1 million in pre-tax finance expenses. For the year ended December 31, 2010, the Company recorded reduced accretion of $1 million in pre-tax finance expenses.

The total impact of this change to asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in finance expenses	$ (1)	$ -
Adjustment before income taxes	$ (1)	$ -

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in property, plant and equipment	$ (38)	$ (38)	$ (49)
Decrease/(increase) in asset retirement obligations	(4)	(4)	6
Increase in retained earnings	$ (42)	$ (42)	$ (43)

Except where indicated and per share amounts, all dollar amounts are in millions.

Under Canadian GAAP accretion of the asset retirement obligations was included in cost of sales and operating expenses; however, under IFRS accretion is now classified in finance expenses.

ii) Onerous Contracts

Under IAS 37, contracts that are deemed loss-making or onerous are recognized as a present obligation when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received from the contract. There are no equivalent requirements under Canadian GAAP. The Company recorded a provision for a drilling rig commitment that was deemed onerous resulting in an increase in provisions of $1 million at January 1, 2010 with a corresponding decrease in retained earnings. For the three months ended March 31, 2010, the Company recognized an additional provision of $1 million with a corresponding expense recorded to other-net. The total provision for the year ended December 31, 2010 was $1 million.

g) IFRS 2 Adjustments – Share-Based Payments

The Company has granted cash-settled share-based payments to certain employees in the past. Under IFRS the related liability is adjusted to reflect the fair value of the outstanding cash-settled shared-based payment using an option pricing model. Canadian GAAP permitted share-based payments to be accounted for by reference to their intrinsic value.

The impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in selling, general and administrative expenses	$ (13)	$ (11)
Adjustment before income taxes	$ (13)	$ (11)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in accounts payable and accrued liabilities	$ 22	$ 16	$ 10
Increase in other long-term liabilities	10	5	9
Decrease in retained earnings	$ 32	$ 21	$ 19

h) IAS 16 Adjustments – Property, Plant and Equipment

The Company reviewed the major components and useful lives of items of property, plant, and equipment. As a result of the retroactive treatment of component depreciation, the Company decreased property, plant and equipment by $144 million with an adjustment to opening retained earnings.

The Company also reviewed replacement of major components to determine if assets replaced prior to the end of their useful life required derecognition under IFRS. The Company determined that asset components with a net book value of $3 million required derecognition which was recorded as a decrease to opening retained earnings.

As a result of these adjustments which reduced the net book value of assets on transition to IFRS, the Company recognized reduced pre-tax depletion, depreciation and amortization of $6 million for the three months ended March 31, 2010, and reduced pre-tax depletion, depreciation and amortization of $26 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recognized $2 million on component disposal recorded as an expense to other - net.

Except where indicated and per share amounts, all dollar amounts are in millions.

The total impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Increase/(decrease) in depletion, depreciation and amortization	$ (26)	$ (6)
Increase in other-net	2	-
Adjustment before income taxes	$ (24)	$ (6)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Decrease in property, plant and equipment	$ 147	$ 141	$ 123
Decrease in retained earnings	$ 147	$ 141	$ 123

i) IFRS 3 Adjustments - Business Combinations

Given that the Company elected to apply the IFRS 1 exemption which permits no adjustments to amounts recorded for acquisitions that occurred prior to January 1, 2010, no retrospective adjustments are required. The Company acquired the remaining interest in the Lloydminster upgrader from the Minister of Natural Resources in 1995 and is required to make payments to the Minister from 1995 to 2014 based on average differentials between heavy crude oil feedstock and the price of synthetic crude oil sales. Under IFRS, the Company is required to recognize this contingent consideration at its fair value as part of the acquisition and record a corresponding liability. Under Canadian GAAP, any contingent consideration is not required to be recognized unless amounts are resolved and payable on the date of acquisition. On transition to IFRS, Husky recognized a liability of $85 million, based on the fair value of remaining upside interest payments, with an adjustment to opening retained earnings. For the three months ended March 31, 2010, the Company recognized pre-tax accretion of $3 million in finance expenses under IFRS. For the year ended December 31, 2010, the Company recognized pre-tax accretion of $9 million in finance expenses under IFRS. Changes in forecast differentials used to determine the fair value of the remaining upside interest payments resulted in the recognition of a pre-tax gain of $7 million recorded to other income for the three months ended March 31, 2010 and a pre-tax gain of $41 million for the year ended December 31, 2010.

The total impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Increase in finance expenses	$ 9	$ 3
Decrease in other - net	(41)	(7)
Adjustment before income taxes	$ (32)	$ (4)

Except where indicated and per share amounts, all dollar amounts are in millions.

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in other long-term liabilities	$ 85	$ 81	$ 53
Decrease in retained earnings	$ 85	$ 81	$ 53

j) IAS 23 Adjustments – Borrowing Costs

The Company has elected to commence mandatory capitalization of borrowing costs for all major capital projects as at January 1, 2003, representing the date the Company commenced incurring capital expenditures on its Madura and Liwan projects, as permitted under IFRS 1. As a result, borrowing costs on major capital international upstream exploratory projects increased exploration and evaluation assets by $43 million as at January 1, 2010 with an adjustment to opening retained earnings.

During the year ended December 31, 2010, the major capital projects with capitalized borrowing costs under IFRS were transferred to the development phase and therefore $43 million of capitalized borrowing costs were reclassified to property, plant and equipment. Additionally, the Company capitalized incremental borrowing costs of $9 million in exploration and evaluation assets under IFRS with a corresponding adjustment to finance expenses for the three months ended March 31, 2010 and $6 million in exploration and evaluation assets and $15 million in property, plant, and equipment under for the year ended December 31, 2010.

The total impact of this change decreased/(increased) retained earnings as follows:

Consolidated Statement of Total Comprehensive Income

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Decrease in finance expenses	$ (21)	$ (9)
Adjustment before income taxes	$ (21)	$ (9)

Consolidated Balance Sheets

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Increase in exploration and evaluation assets	$ (43)	$ (52)	$ (6)
Increase in property, plant and equipment	-	-	(58)
Increase in retained earnings	$ (43)	$ (52)	$ (64)

k) IAS 18 Adjustments – Revenue

Under IFRS, realized and unrealized gains and losses on natural gas purchase and sale contracts are recorded on a net basis against sales and operating expenses. Under Canadian GAAP, these gains and losses are recorded on a gross basis. For the three months ended March 31, 2010, the Company reclassified $261 million of losses on natural gas purchase contracts from purchases of crude oil and products to revenues. For the year ended December 31, 2010, the amount reclassified was $852 million.

Except where indicated and per share amounts, all dollar amounts are in millions.

l) IAS 12 Adjustments – Income Taxes

Nearly all recognized IFRS conversion adjustments as discussed in this transition note have related effects on deferred taxes. The tax impact of the above changes (increased)/decreased the deferred tax liability as follows:

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	$ 114	$ 20
Depletion of oil and gas properties *(note a)*	(11)	(12)
Employee benefits *(note b)*	6	-
Foreign currency translation *(note d)*	13	(11)
Impairment of assets *(note e)*	(3)	(1)
Asset retirement obligation *(note f)*	(1)	-
Share-based payments *(note g)*	(4)	(3)
Property, plant and equipment *(note h)*	(7)	(1)
Business combinations *(note i)*	(8)	(2)
Borrowing costs *(note j)*	(5)	(4)
Uncertain tax positions *(note l)*	27	-
Decrease (increase) in deferred tax liability	$ 121	$ (14)

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	$ 154	$ 174	$ 268
Depletion of oil and gas properties *(note a)*	-	(12)	(11)
Employee benefits *(note b)*	16	16	22
Foreign currency translation *(note d)*	7	(4)	20
Impairment of assets *(note e)*	47	46	44
Asset retirement obligation *(note f)*	(16)	(16)	(17)
Share-based payments *(note g)*	10	7	6
Property, plant and equipment *(note h)*	44	43	37
Business combinations *(note i)*	25	23	17
Borrowing costs *(note j)*	(13)	(17)	(18)
Uncertain tax positions *(note l)*	(47)	(47)	(20)
Decrease (increase) in deferred tax liability	$ 227	$ 213	$ 348

Under IFRS, the Company records and measures income tax uncertainties based on a single best estimate. Under Canadian GAAP the Company recorded uncertain tax positions if such positions were probable of being sustained. The impact of this change increased the deferred tax liability by $47 million as at January 1, 2010 and March 31, 2010, and $20 million as at December 31, 2010 under IFRS.

For the three months ended March 31, 2010, the Company recorded additional deferred income tax expense of $14 million which was recorded to net earnings.

For the year ended December 31, 2010, the Company recorded reduced deferred income tax expense of $115 million and $6 million which were recorded to net earnings and OCI respectively.

Except where indicated and per share amounts, all dollar amounts are in millions.

m) Retained Earnings Adjustments

The above changes (increased)/decreased retained earnings (each net of related tax) as follows:

	For the year ended Dec. 31, 2010	For the three months ended March 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	$ 324	$ 29
Depletion of oil and gas properties *(note b)*	(33)	(15)
Employee benefits *(note b)*	-	-
Government grants *(note c)*	-	-
Foreign currency translation *(note d)*	37	(15)
Impairment of assets *(note e)*	(7)	(2)
Asset retirement obligation *(note f)*	(3)	(1)
Provisions – onerous contracts *(note f)*	1	1
Share-based payments *(note g)*	(9)	(8)
Property, plant and equipment *(note h)*	(17)	(5)
Business combinations *(note i)*	(24)	(2)
Borrowing costs *(note j)*	(16)	(5)
Uncertain tax positions *(note l)*	(27)	-
Decrease (increase) in retained earnings	$ 226	$ (23)

	As at January 1, 2010	As at March 31, 2010	As at December 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	$ 362	$ 391	$ 686
Depletion of oil and gas properties *(note a)*	-	(15)	(33)
Employee benefits *(note b)*	37	37	37
Government grants *(note c)*	2	2	2
Foreign currency translation *(note d)*	58	43	95
Impairment of assets *(note e)*	110	108	103
Asset retirement obligation *(note f)*	(39)	(40)	(42)
Provisions – onerous contracts *(note f)*	1	2	2
Share-based payments *(note g)*	22	14	13
Property, plant and equipment *(note h)*	103	98	86
Business combinations *(note i)*	60	58	36
Borrowing costs *(note j)*	(30)	(35)	(46)
Uncertain tax positions *(note l)*	47	47	20
Decrease in retained earnings	$ 733	$ 710	$ 959

n) Reclassifications

Certain amounts have been reclassified to conform with current presentation.