REPORT OF ERNST & YOUNG LLP,
INDEPENDENT AUDITORS

Board of Directors and Shareholder
BP America Inc.

We have audited the accompanying consolidated balance sheets of BP America Inc. (an indirect wholly owned subsidiary of BP p.l.c.) and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of BP America Inc. and subsidiaries at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

In forming our opinion we have considered the adequacy of the disclosures made in Notes 2, 10 and 14 to the financial statements concerning the accruals, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by the Company in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to the Company will be dependent on many factors. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses. Our opinion is not qualified in respect of these matters.

Ernst & Young LLP

Houston, Texas
March 23, 2011

BP AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

Millions of Dollars - Year Ended December 31	2010	2009	2008
		as Adjusted	
Revenues			
Sales and operating revenue	$ 133,258	$ 109,465	$ 162,417
Excise taxes	11,504	10,760	10,792
Equity in income of affiliates and other	1,711	1,197	712
Gain on sale of businesses and fixed assets	5,283	1,689	134
	151,756	123,111	174,055
Costs and Expenses			
Purchases	88,150	70,387	106,045
Operating expenses	48,634	14,705	15,555
Oil and gas exploration expenses including amortization of unproved properties	500	725	484
Taxes other than income taxes	13,558	12,089	14,404
Depreciation, depletion and amortization, and retirements and abandonments	8,708	8,423	6,880
Impairment of goodwill	-	1,795	-
Selling, general and administrative expenses	5,527	7,081	6,783
	165,077	115,205	150,151
(Loss) Income Before Interest and Income Taxes	(13,321)	7,906	23,904
Interest expense	1,609	1,139	1,397
Interest income	177	198	615
(Loss) Income Before Income Taxes	(14,753)	6,965	23,122
Income tax (benefit) provision	(3,364)	3,054	9,098
Net (Loss) Income	(11,389)	3,911	14,024
Net income attributable to non-controlling interests	1,028	854	1,296
Net (Loss) Income Attributable to the Company	$ (12,417)	$ 3,057	$ 12,728

The accompanying notes are an integral part of these consolidated financial statements.

BP AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

Millions of Dollars - December 31		**2010**		**2009**
				as Adjusted
ASSETS				
Current Assets				
Cash and cash equivalents	$	656	$	520
Investments		1,122		-
Accounts and notes receivable		12,077		12,311
Receivables – affiliates		10,671		7,854
Inventories		3,819		4,459
Prepaid expenses and other		9,898		5,647
Assets held for sale		4,915		-
		43,158		30,791
Property, Plant and Equipment - at cost				
Exploration and production		130,494		133,246
Refining and marketing		30,344		32,323
Corporate and other		2,076		1,836
		162,914		167,405
Less accumulated depreciation, depletion and amortization		81,531		84,569
		81,383		82,836
Other Non-Current Assets				
Investments in affiliates		12,044		8,805
Amounts due from affiliates		9,592		8,222
Investments, long-term receivables and other		5,533		5,840
Goodwill		5,759		6,066
		32,928		28,933
	$	157,469	$	142,560

The accompanying notes are an integral part of these consolidated financial statements.

BP AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

Millions of Dollars - December 31	2010	2009
		as Adjusted
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Current portion of long-term debt	$ 485	$ 43
Current portion of long-term debt – affiliates	-	1,410
Short-term obligations	4,555	4,565
Accounts payable – trade	15,588	13,428
Accounts payable – affiliates	1,759	2,410
Taxes payable, including income taxes	2,392	1,643
Accrued liabilities	13,997	6,894
Liabilities held for sale	308	-
	39,084	30,393
Long-Term Obligations		
Amounts due to affiliates	2,923	2,766
Long-term debt	5,301	4,448
Long-term debt – affiliates	33,850	27,205
	42,074	34,419
Other Non-Current Liabilities		
Deferred income taxes	9,133	12,678
Accruals and reserves	25,461	16,144
	34,594	28,822
Shareholder's Equity		
Common stock - 5,743,143 Class A and 2,129,809 Class B shares issued and outstanding	8	8
Additional paid-in capital	43,720	37,974
(Accumulated deficit) Retained earnings	(629)	11,794
Accumulated other comprehensive (loss) income:		
Foreign currency translation adjustment	(1,171)	(582)
Postretirement benefit plans	(2,690)	(2,403)
Unrealized gain on investments	4	91
Hedging activities	-	(4)
Company shareholder's equity	39,242	46,878
Non-controlling interests	2,475	2,048
	41,717	48,926
	$ 157,469	$ 142,560

The accompanying notes are an integral part of these consolidated financial statements.

BP AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDER'S EQUITY

Millions of Dollars	Common Stock	Additional Paid-in Capital	Retained Earnings/ Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
January 1, 2008, as Reported	$ 8	$ 36,416	$ 6,324	$ (486)	$ 3,129	$ 45,391
Prior period adjustments		951	-			951
January 1, 2008 *as Adjusted*	8	37,367	6,324	(486)	3,129	46,342
Net income	-	-	12,728	-	1,296	14,024
Other comprehensive income (loss), net of						
applicable income tax - shown in parentheses						
Foreign currency translation adjustment	-	-	-	(1,225)	(159)	(1,384)
Postretirement benefit plans ($1,077)	-	-	-	(1,922)	(27)	(1,949)
Unrealized loss on investments ($50)	-	-	-	(86)	-	(86)
Hedging activities ($4)	-	-	-	8	-	8
Comprehensive income						10,613
Purchase of subsidiary shares from non-controlling interests	-	(39)	-	-	(199)	(238)
Dividends on subsidiary common stock paid to non-controlling interests	-	-	-	-	(1,120)	(1,120)
Cash dividends paid	-	-	(338)	-		(338)
Fair value measurements ($12)	-	-	23	-	-	23
Increase in additional paid-in-capital resulting from asset transfers within the BP group	-	134	-	-	-	134
Share based compensation		316				316
December 31, 2008 *as Adjusted*	8	37,778	18,737	(3,711)	2,920	55,732
Net income	-	-	3,057	-	854	3,911
Other comprehensive income (loss), net of						
Applicable income tax - shown in parentheses						
Foreign currency translation adjustment	-	-	-	389	(160)	229
Postretirement benefit plans ($238)	-	-	-	403	62	465
Unrealized gain on investments ($14)	-	-	-	27	-	27
Hedging activities ($1)	-	-	-	(6)	-	(6)
Comprehensive income						4,626
Purchase of subsidiary shares from non-controlling interests	-	(3)	-	-	(35)	(38)
Dividends on subsidiary common stock paid to non-controlling interests and return of capital *asAdjusted*	-	-	-	-	(1,593)	(1,593)
Cash dividends paid	-	-	(10,000)	-		(10,000)
Share based compensation		199		-	-	199
December 31, 2009 *as Adjusted*	8	37,974	11,794	(2,898)	2,048	48,926
Net income (loss)	-	-	(12,417)	-	1,028	(11,389)
Other comprehensive income (loss), net of						
Applicable income tax - shown in parentheses						
Foreign currency translation adjustment	-	-	-	(589)	253	(336)
Postretirement benefit plans ($12)	-	-	-	(287)	(29)	(316)
Unrealized loss on investments ($51)	-	-	-	(87)	-	(87)
Hedging activities ($1)	-	-	-	4	-	4
Comprehensive loss						(12,124)
Issuance of non-controlling interests subsidiary shares	-	-	-	-	300	300
Dividends on subsidiary common stock paid to non-controlling interests	-	-	-	-	(641)	(641)
Increase in additional paid-in-capital and reduction to non-controlling interests resulting from asset transfers within the BP group	-	5,443	-	-	(484)	4,959
Share based compensation		303	(6)	-	-	297
December 31, 2010	$ 8	$ 43,720	$ (629)	$ (3,857)	$ 2,475	$ 41,717

The accompanying notes are an integral part of these consolidated financial statements.

BP AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of Dollars - Year Ended December 31	2010	2009	2008
		as Adjusted	
Operating Activities			
Net (loss) income	$ (11,389)	$ 3,911	$ 14,024
Adjustments to reconcile net (loss) income to net cash (used in) provided by operations:			
Depreciation, depletion, amortization, retirements, abandonments and impairments	8,708	10,218	6,880
Amortization of unproved oil and gas properties	292	498	219
Deferred income taxes	(7,166)	55	1,087
Gain on sales of assets	(5,283)	(1,689)	(134)
Equity in income of affiliates, net of dividends received	(471)	(599)	(205)
Share based compensation	303	199	316
Changes in operating assets and liabilities, net of acquisitions and divestments:			
Decrease (increase) in marketable securities	-	39	(30)
(Increase) decrease in accounts and notes receivable	(1,700)	752	2,336
(Increase) decrease in receivables – affiliates	(602)	1,175	(853)
(Increase) decrease in inventories and prepaid expenses	(2,542)	1,740	(163)
(Increase) decrease in other assets	(1,705)	2,203	(2,462)
Increase (decrease) increase in accounts payable and accrued liabilities	10,893	(727)	(2,506)
(Decrease) increase in accounts payable - affiliates	(272)	345	(1,215)
Increase (decrease) in taxes payable	869	(1,080)	354
Increase (decrease) in other liabilities	7,364	(3,479)	914
Net cash (used in) provided by operating activities	(2,701)	13,561	18,562
Investing Activities			
Capital expenditures and acquisitions	(13,892)	(15,109)	(16,055)
Proceeds from the sale of property and other assets	13,251	1,758	622
Investments in affiliates, net	(9)	536	131
Net cash used in investing activities	(650)	(12,815)	(15,302)
Financing Activities			
Net changes in long-term debt	1,295	(29)	(482)
Net changes in long-term debt - affiliates	11,081	20,215	(7,727)
Net changes in notes and amounts due to and from affiliates and receivables and payables - affiliates	(4,183)	(8,624)	6,358
Net changes in short-term obligations	(4,082)	(714)	211
Dividends paid on common stock	-	(10,000)	(338)
Dividends paid to non-controlling interest and return of capital	(641)	(1,628)	(1,505)
Increase in additional paid-in-capital from asset transfers within the BP group	-	-	134
Other, net	17	-	(39)
Net cash provided by (used in) financing activities	3,487	(780)	(3,388)
Increase (decrease) in Cash and Cash Equivalents	136	(34)	(128)
Cash and cash equivalents, Beginning of Year	520	554	682
Cash and cash equivalents, End of Year	$ 656	$ 520	$ 554

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Organization and Accounting Changes

BP America Inc. (the Company) is an indirect wholly owned subsidiary of BP p.l.c. (BP). BP and its subsidiaries are hereafter referred to as the BP group.

Events subsequent to December 31, 2010 were evaluated through the date these consolidated financial statements were available to be issued, March 23, 2011.

In December 2010, the Company's ownership interest in a consolidated entity, BP Australia Group Limited (BPAGL), was diluted from 75 percent to 49 percent. The reduction resulted from BPAGL transferring additional shares to a United Kingdom owned affiliate of the Company, BP Australia Investments Limited (BPAIL), in exchange for a loan receivable. The Company's remaining ownership interest in BPAGL was converted to a preferred stock investment valued at $5.7 billion. At December 31, 2010, BPAGL was no longer a consolidated entity of the Company.

Certain adjustments have been made to the prior period consolidated financial statements as follows:

a) To present gains and losses on forward commodity contracts, on a net basis within sales and operating revenue for derivative financial instruments held for trading purposes.
b) To present certain receivable and payable balances with the Company's affiliates as short term where contractual terms permit settlement on demand.
c) To present the expense offset for equity settled awards issued to the Company's employees as a contribution, net of applicable tax, from BP.
d) To reflect the payment of the return of a consolidated majority owned subsidiary's capital to an affiliate of BP.

The following tables summarize the adjustments made to the prior period consolidated financial statements.

Consolidated Statement of Operations

Millions of Dollars - Year Ended December 31		2009			2008	
	as Reported	Adjust-ments	*as Adjusted*	as Reported	Adjust-ments	*as Adjusted*
Revenues	$ 128,214	$ (5,103)	$123,111	$ 179,228	$(5,173)	$ 174,055
Costs and Expenses	120,308	(5,103)	115,205	155,324	(5,173)	150,151
Income Before Interest and Income Taxes	7,906	-	7,906	23,904	-	23,904

Consolidated Balance Sheet

Millions of Dollars - December 31	2009		
	as Reported	Adjustments	*as Adjusted*
Current assets	$ 22,576	$ 8,215	$ 30,791
Property, plant and equipment, net	82,836	-	82,836
Other non-current assets	36,148	(7,215)	28,933
Total assets	$ 141,560	$ 1,000	$ 142,560
Current liabilities	$ 30,260	$ 133	$ 30,393
Long-term obligations	34,975	(556)	34,419
Other non-current liabilities	28,139	683	28,822
Company shareholder's equity	45,412	1,466	46,878
Non-controlling interests	2,774	(726)	2,048
Total liabilities and shareholder's equity	$ 141,560	$ 1,000	$ 142,560

Consolidated Statement of Cash Flows

Millions of Dollars - Year Ended December 31	2009			2008		
	as Reported	Adjust-ments	*as Adjusted*	as Reported	Adjust-ments	*as Adjusted*
Net cash provided by operating activities	$ 13,420	$ 141	$ 13,561	$ 18,300	$ 262	$ 18,562
Net cash used in investing activities	(12,850)	35	(12,815)	(15,687)	385	(15,302)
Net cash used in financing activities	(604)	(176)	(780)	(2,741)	(647)	(3,388)

Note 1 Summary of Significant Accounting Policies

Principles of consolidation. The assets, liabilities and results of operations of subsidiaries in which the Company has a controlling interest and variable interest entities where the Company is the primary beneficiary are included in the consolidated financial statements. The equity method is used to account for investments in affiliates in which the Company has less than a controlling interest, but has the ability to exert significant influence over the affiliates' operating and financial policies. The Company also consolidates its proportionate share of undivided interests in certain pipelines and oil and gas joint ventures. All significant intercompany transactions and accounts are eliminated in consolidation.

Use of estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect certain reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from estimates and assumptions made.

Foreign currencies. Functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash. Assets and liabilities of non-US subsidiaries using the local currency as their functional currency are translated at exchange rates in effect at the balance sheet date. Income and expenses are translated at average exchange rates for the period presented. The effects of these translation adjustments are reported in other comprehensive income. Exchange gains and losses arising from transactions denominated in a currency, other than the functional currency of the entity involved are recognized in income.

Goodwill. Goodwill is the excess of the consideration transferred over the value of net assets recognized and represents the future economic benefits arising from assets acquired. Goodwill is evaluated for impairment on at least an annual basis.

Assets held for sale. Assets and disposal groups classified as held for sale are measured at the lower of carrying amount or fair value less costs to sell. Assets and disposal groups are classified as held for sale if their carrying amounts are expected to be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale which should be expected to qualify as a completed sale within one year from the date of classification as held for sale. Property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

Dispositions. Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the Company. Losses on properties sold are recognized when incurred or impairment is recognized when the properties are held for sale and the fair value of the properties is less than the carrying value.

Revenue recognition. Revenues associated with the sale of oil, natural gas liquids, liquefied natural gas, petroleum and chemical products and all other items are recognized when title passes to the customer. Revenues associated with producing properties in which the Company has an interest with other producers are recognized on an entitlement basis, with the cumulative difference between the Company's working interest share and actual sales recorded as an asset or liability at current market prices.

Shipping and handling costs. Shipping and handling costs are included in purchases.

Inventories. Inventories are carried at the lower of current market value or cost. Cost is determined under the last-in, first-out (LIFO) method for a portion of the inventories of crude oil, natural gas, petroleum products and chemical products. The costs of remaining inventories are determined on the first-in, first-out (FIFO) or average cost methods. Costs are comprised of direct purchase costs, cost of production, transportation and manufacturing expenses.

Fair value measurement. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 or 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

Derivative financial instruments. The Company uses derivative financial instruments to manage certain exposures to commodity prices as well as for trading purposes. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive or as liabilities when the fair value is negative. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheet and the collateral paid or received is netted against derivative assets and derivative liabilities, respectively. Gains and losses arising from changes in the fair value of derivatives are recognized in the consolidated statement of operations.

Oil and gas exploration and development. The Company follows the successful efforts method of accounting. Costs of property acquisitions, successful exploratory wells, all development costs (including CO_2 and certain other injected materials that benefit production over multiple years in enhanced recovery projects) and support equipment and facilities are capitalized. Unsuccessful exploratory wells are expensed when determined to be non-productive. Production costs, overhead and all exploration costs other than exploratory drilling, including geological and geophysical costs, are charged against income as incurred.

Exploration license acquisition costs are initially capitalized as an intangible fixed asset and are amortized over the estimated period of exploration. Where proved reserves of oil or natural gas are determined and development is sanctioned, the unamortized cost is transferred to tangible production assets. Where exploration is unsuccessful, the unamortized cost is expensed.

Property acquisition costs for individually significant unproved properties are assessed at least annually for impairment. The acquisition costs of all other unproved properties are aggregated, and the portion estimated to be nonproductive based upon past experience is amortized over the projected holding periods.

Property, plant and equipment. Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any asset retirement obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the relinquished asset is reliably measurable. The cost of the acquired asset is measured at the fair value of the relinquished asset, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the relinquished asset. The gain or loss on derecognition of the relinquished asset is recognized in the consolidated statement of operations.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Overhaul costs for major maintenance programs, and all other maintenance costs are expensed as incurred.

Depletion of the cost of producing oil and gas properties, amortization of related intangible drilling and development costs and depreciation of tangible leases and well equipment are recognized using the unit-of-production method. Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The useful lives of the Company's other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemical plants	20 to 30 years
Pipelines	Unit-of- throughput / 10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively. The carrying value of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the consolidated statement of operations in the period in which the item is derecognized.

Impairment of intangible assets and property, plant and equipment. The Company assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, for example, low prices or margins for an extended period or, for oil and gas assets, significant downward revisions of estimated volumes or increases in estimated future development expenditure. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level for which independent cash flows of long-lived assets can be identified from other groups of assets and liabilities. Assets that are to be held and used with recorded values that are not expected to be recovered through future cash flows are written down to current fair value. In assessing the fair value, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

Asset retirement obligations. The Company incurs retirement obligations for certain assets, including oil and gas producing properties at the time they are installed. The fair values of these obligations are initially recorded as liabilities on a discounted basis. The costs associated with these liabilities are capitalized as part of the related assets and depreciated over the useful lives of the related assets. Over time, the liabilities are accreted for the change in their present value. Asset retirement obligations associated with refining, pipeline and marketing assets are generally not provided for as such obligations cannot be measured given their indeterminate settlement dates. The Company performs periodic reviews of these long-lived assets for any change in facts and circumstances that might require the recognition of an asset retirement obligation.

Environmental liabilities. Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties and projected cash expenditures are presented on an undiscounted basis.

Contingencies. The Company is subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. The Company accrues losses associated with legal claims when those losses are probable and reasonably estimable. Estimates are adjusted as additional information becomes available or circumstances change. Accrued losses are presented on an undiscounted basis. Amounts that the Company has a contractual right to recover from third parties are contingent assets. Such amounts are recognized only when realized.

Income taxes. Income tax expense represents the sum of tax currently payable and deferred tax. Estimates of interest and penalties relating to tax are also included in income tax expense. The tax currently payable is based on the taxable profits for the period. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of the Company's assets and liabilities. Allowable tax credits are applied currently as reductions of the provision for income taxes.

Reclassifications. Certain reclassifications have been made to prior year balances in order to conform to current year presentation.

New Accounting Standards.

In January 2010, the FASB issued ASU No. 2010-06, *Improving Disclosures about Fair Value Measurements*. This update requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. This update also clarifies existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). With the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be effective January 1, 2011, the provisions in ASU 2010-06 became effective January 1, 2010. The adoption did not impact the Company's operating results, financial position or cash flows, but did impact the Company's disclosures on fair value measurements. See Note 7.

In June 2009, the FASB issued ASU 2009-16, *Accounting for Transfers of Financial Assets*. This update eliminates the exceptions for qualifying special-purpose entities from the consolidating guidance and changes how companies account for transfers of financial assets. This new guidance enhances disclosures about the risks that a transferor continues to be exposed to because of its continuing involvement in transferred financial assets. The update became effective for the Company on January 1, 2010 but did not have an effect on the Company's results of operations, financial position or cash flows.

Note 2 Significant event – Gulf of Mexico oil spill

On April 20, 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon and on April 22 the vessel sank. Tragically, 11 people lost their lives and 17 others were injured. Hydrocarbons continued to flow from the reservoir and up through the casing and the blowout preventer (BOP) for 87 days, causing a very significant oil spill. The Deepwater Horizon rig was operated by Transocean Holdings LLC and was drilling the Macondo exploration well. The well forms part of the Mississippi Canyon Block 252 (MC252) lease, in respect of which BP Exploration & Production Inc., a subsidiary, was the named party and operator with a 65% working interest. The well was in a water depth of 5,000 feet and 43 nautical miles from shore. The Company tackled the leak at its source in multiple, parallel ways, which over time included: attempting to fit caps on the well, using containment systems to pipe oil to vessels on the surface, sealing the well through a static-kill procedure and drilling relief wells. The Company recognized early in the incident that drilling relief wells constituted the ultimate means to seal and isolate the well permanently and stop the flow of oil and gas. Two relief wells were drilled, the first of which was started on May 2; the second was started on May 16 as a contingency.

On July 15, the Company successfully shut in the Macondo well and then commenced a static-kill procedure. On August 9, the Company confirmed that the casing had been successfully sealed with cement. On September 16, the first relief well intercepted the annulus of the Macondo well. After completing cementing operations on September 19, the Company, the federal government scientific team and the National Incident Commander concluded that the well-kill operations had successfully sealed the annulus. The Company then began the abandonment of the Macondo well, which included removing portions of the casing and setting cement plugs. This work was completed on November 8. In parallel, operations to plug and abandon (P&A) the relief well that intercepted the Macondo well also took place and were completed on September 30. P&A of the second relief well was completed on March 8, 2011. All response activities at the Macondo site (with the exception of the final seabed survey and seismic sweep, which are scheduled to take place later in 2011), were completed on January 8 with the recovery of the buoy and anchor system for the free-standing riser.

As a consequence of the Gulf of Mexico oil spill, as described above, the Company has incurred costs during the year and has recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed. These are discussed in further detail in Note 10 Litigation and Contingencies and Note 14, Accruals and Reserves. The Company also has rights and obligations in relation to the $20 billion trust fund which was established during the year. The trust fund is detailed further in this Note, Note 6, Note 10 and Note 14.

Through a subsidiary of BP, the Company has insurance policies related to oil spill response and claims and control of well costs. As of December 31, 2010, the Company received $590 million and does not anticipate further recoveries from these policies.

The financial impacts of the Gulf of Mexico oil spill on the consolidated statement of operations, consolidated balance sheet and consolidated statement of cash flows of the Company are shown in the table below.

Millions of Dollars - Year Ended December 31, 2010		
Consolidated Statement of Operations		
Revenue (Insurance recoveries)	$	590
Operating Expenses		33,182
Loss Before Income Taxes		(32,592)
Less: Income Tax Benefit		10,030
Net Loss	$	(22,562)

Millions of Dollars - December 31, 2010		
Consolidated Balance Sheet		
Current assets:		
Prepaid expenses and other	$	4,897
Current liabilities:		
Accounts payable trade		(1,580)
Accrued liabilities		(7,888)
Net current liabilities		(4,571)
Non-current liabilities:		
Deferred income taxes		5,610
Accruals and reserves		(8,020)
Net non-current liabilities		(2,410)
Net Assets	$	(6,981)

Millions of Dollars - Year Ended December 31, 2010		
Consolidated Statement of Cash Flows		
Loss before income taxes	$	(32,592)
Changes in operating assets and liabilities:		
Increase in inventories and prepaid expenses		(1,959)
Increase in accounts payable and accrued liabilities		9,468
Increase in other liabilities		8,020
Pre-tax cash flows used in operations	$	(17,063)

The Company has established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by the

Company, final judgments and settlements, state and local response costs, and natural resource damages and related costs. In 2010 the Company contributed $5 billion to the fund, and further quarterly contributions of $1.25 billion are to be made during 2011 to 2013. Fines, penalties and claims administration costs are not covered by the trust fund. The establishment of the trust fund does not represent a cap or floor on the Company's liabilities and the Company does not admit to a liability of this amount.

Under the terms of the Trust agreement, the Company has no right to access the funds once they have been contributed to the trust fund and the Company has no decision-making role in connection with the payment by the trust fund of individual and business claims resolved by the GCCF. The Company will receive any amounts remaining from the trust fund only upon its expiration, if there are any amounts remaining at that point. The Company has the authority under the Trust agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the Trustees with all the required documents establishing that such claims are valid under the Trust agreement. However, any such payments can only be made on the authority of the Trustees and any funds distributed are paid directly to the claimants, not to the Company. The Company will not settle any such items directly or receive reimbursement from the trust fund for such items

The trust fund is included in "Prepaid expenses and other" in the consolidated balance sheet. The Company's obligation to the trust fund will be recognized as the Company makes payments, in accordance with the terms of the Trust agreement. As the payments are made, these are recognized on the Company's consolidated balance sheet as an increase to restricted cash within "Prepaid expenses and other" until such time as the Trustees make eligible payments, per the Trust agreement, which reduces the restricted cash balance. In addition to the Company's contributions of $5 billion to the trust fund during 2010, the Company has a remaining commitment, at December 31, 2010 of $15 billion. The portion of the accrued liabilities recognized during the year for items that will be covered by the trust fund was $12,567 million. Of this amount, payments of $3,033 million were made during the year from the trust fund. The remaining trust fund balance at December 31, 2010 was $1,959 million.

Movements in the trust fund, including the liabilities paid out of the trust fund, are presented below.

Millions of Dollars		
Trust fund payments	$	5,000
Amounts paid directly by the trust fund		(3,033)
Trust related interest/expenses		(8)
Balance at December 31, 2010	$	1,959

Any increases in accrued liabilities that will be covered by the trust fund will be recognized in the consolidated statement of operations. Movements in the obligations accrued that are paid out of the trust fund, are presented below.

Millions of Dollars		
Increase liabilities for items covered by the trust fund	$	12,567
Amounts paid directly by the trust fund		(3,033)
At December 31, 2010	$	9,534
Of which – current (accrued liabilities)		5,933
– non-current (accrual and reserves)		3,601

Future changes in amounts provided could arise from adjustments to existing accrued liabilities, or from the initial recognition of accrued liabilities for items that currently cannot be estimated reliably, namely final judgments and settlements and natural resource damages and related costs. It is not possible at this time to conclude as to whether the $20 billion fund will be sufficient to satisfy all claims under the Oil Pollution Act of 1990 (OPA 90) that will ultimately be paid. Further information on those items that currently cannot be reliably estimated is provided under Litigation and Contingencies in Note 10. The Trust agreement does not require the Company to make further contributions to the trust fund in excess of the agreed $20 billion should this be insufficient to cover all claims administered by the GCCF, or to settle other items that are covered by the trust fund, as described above. Should the $20 billion trust fund not be sufficient, the Company would commence settling legitimate claims and other costs by making payments directly to claimants.

On September 30, 2010, the Company pledged certain Gulf of Mexico assets as collateral for the trust fund funding obligation. The pledged collateral consists of an overriding royalty interest in oil and gas production of Thunder Horse, Atlantis, Mad Dog, Great White and Mars, Ursa and Na Kika assets in the Gulf of Mexico. A wholly-owned company called Verano Collateral Holdings LLC (Verano) has been created to hold the overriding royalty interest, which is capped at $1.25 billion per quarter and $17 billion in total. Verano has pledged the overriding royalty interest to the Trust as collateral for the Company's remaining contribution obligations to the Trust. The Company contributed a further $2 billion to the trust fund since this arrangement was established, thereby reducing the amount of the pledge to $15 billion at the end of the year. There is no change in operatorship or the marketing of the production from the assets and there is no effect on the other partners' interests in the assets. For financial reporting purposes, Verano is a consolidated entity of the Company and there is no impact on the consolidated financial statements from the pledge of the overriding royalty interest. At December 31, 2010 the Company has recorded certain liabilities and disclosed certain contingencies as a consequence of the Gulf of Mexico oil spill. These are described below under the OPA 90 and Other items.

Oil Pollution Act of 1990

The claims against the Company under the OPA 90 and for personal injury fall into three categories: (i) claims by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity, loss of subsistence use of natural resources and for personal injury (Individual and Business Claims); (ii) claims by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs (State and Local Claims); and (iii) claims by the United States, a State trustee, an Indian tribe trustee, or a foreign trustee for natural resource damages (Natural Resource Damages claims). In addition, the Company faces civil litigation in which claims for liability under the OPA 90, along with other causes of actions, including personal injury claims, are asserted by individuals, businesses, and government entities. A liability has been recorded for Individual and Business Claims and State and Local Claims. A liability has also been recorded for claims administration costs and natural resource damage assessment costs.

The Company considers that it is not possible to measure reliably any obligation in relation to Natural Resource Damages claims under the OPA 90 or litigation for violations of the OPA 90. These items are therefore disclosed as contingent liabilities. The $20 billion trust fund described above is available to satisfy the OPA 90 claims and litigation referred to above with the exception of claims administration costs which are borne separately by the Company. The establishment of the trust fund does not represent a cap or floor on the Company's liabilities and the Company does not admit to a liability for this amount.

Other items

Accrued liabilities and accruals and reserves at December 31, 2010 also include amounts in relation to offshore and onshore oil spill response, estimated penalties for liability under the Clean Water Act Section 311, and legal fees where the Company has been able to estimate reliably those which will arise in the next two years. These are not covered by the trust fund. The liability recorded does not reflect any amounts in relation to fines and penalties except for those relating to the Clean Water Act, as it is not possible to estimate reliably either the amount or timing of such additional items. The Company also considers that it is not possible to measure reliably any obligation in relation to litigation or any obligation in relation to legal fees beyond two years. These items are therefore disclosed as contingencies. No amounts have been recognized for recovery of costs from the co-owners of the Macondo well. These items are disclosed as contingent assets. See Note 10 for details.

A liability has been recognized for estimated future expenditure relating to the oil spill, for items that can be reliably measured at this time, in accordance with the Company's accounting policy for contingencies, as described in Note 1. The total amount recognized in the Company's consolidated statement of operations (not including insurance recoveries) during the year was $33,182 million (including $12,567 million for items covered by the trust fund and $20,615 million for other items). After deducting amounts paid during the year totaling $13,935 million (including payments from the trust fund of $3,033 million and payments made directly by the Company of $10,902 million), the remaining accrual as at December 31, 2010 was $15,908 million. Movements in the total liability are presented in the table below.

Millions of Dollars		
Increase in liabilities – items not covered by the trust fund	$	17,276
– items covered by the trust fund		12,567
– payments by the Company		(10,902)
– payments by the trust fund		(3,033)
At December 31, 2010	$	15,908
Of which - current (accrued liabilities)		7,888
- non-current (accruals and reserves)		8,020

The total amounts that will ultimately be paid by the Company in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to the Company will be dependent on many factors. Furthermore, the amount of claims that become payable by the Company, the amount of fines ultimately levied on the Company (including any determination of the Company's negligence), the outcome of litigation, and any costs arising from any longer-term environmental consequences of the oil spill, will also impact upon the ultimate cost for the Company. Although the liabilities recognized are the current best estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably, as noted above.

Impact on Consolidated Statement of Operations and Consolidated Statement of Cash Flows

The Company's consolidated statement of operations for 2010 includes a pre-tax charge of $32,592 million, net of insurance recoveries, in relation to the Gulf of Mexico oil spill. This comprises costs incurred up to December 31, 2010, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund.

The amount of the accrued liabilities recognized during the year can be reconciled to the consolidated statement of operations charge as follows:

Millions of Dollars		
Increase in accrued liabilities and accruals and reserves	$	29,843
Costs charged directly to the consolidated statement of operations		3,339
Insurance recoveries		(590)
At December 31, 2010	$	32,592

The total charge in the consolidated statement of operations, related to the Gulf of Mexico oil spill is analyzed in the table below. Costs charged directly to the consolidated statement of operations in relation to spill response, environmental and litigation and claims are those that arose prior to recording the liability at the end of the second quarter of 2010 ($3,339 million). These are presented, by category, in the table below.

Millions of dollars		**Total**
Spill response – amounts provided	$	10,883
– costs charged directly to the consolidated statement of operations		2,745
Total charge relating to spill response		13,628
Environmental – amount provided		511
– costs charged directly to the consolidated statement of operations		70
Total charge relating to environmental		581
Litigation and claims – amount provided		14,939
– costs charged directly to the consolidated statement of operations		184
Total charge relating to litigation and claims		15,123
Clean Water Act penalties – amount provided		3,510
Other costs charged directly to the consolidated statement of operations		332
Other (trust expense)		8
Insurance recoveries		(590)
Total loss before interest and tax	$	32,592

The total amounts that will ultimately be paid by the Company in relation to all obligations relating to the incident are subject to significant uncertainty as described above. Response operations following the Deepwater Horizon incident in April 2010 have been managed by the federal government's response framework, which transitioned on December 17, 2010 from the Unified Area Command (UAC) to the Gulf Coast Incident Management Team (GC-IMT). Both the UAC and now the GC-IMT link the organizations responding to the incident and provide a forum for those organizations to make consensus decisions. If consensus cannot be reached, the US Coast Guard coordinator carries the final decision on response related actions deemed necessary. As such, the activities undertaken by the Company and its sub-contractors, and the associated costs, are not wholly within the Company's control. This will continue to be the case until control of the response operations transitions to the Gulf Coast Restoration Organization.

Numerous personnel and vessels were involved in activities which included skimming, boom deployment and shoreline clean up. Due to the scale of the incident and the need to respond rapidly, procurement authority was vested with state on-scene coordinators, various responsible parties and various state and local government authorities. So long as the expenses incurred are found to be consistent with the National Contingency Plan, the responsible parties will be expected to pay these costs, regardless of whether or not they were involved in or approved the decision to procure the resource. With the large number of parties involved, the resulting funding flows are complex and resulted in difficulty maintaining real time monitoring of expenses. The impact on net cash used in operating activities, on a pre-tax basis, amounted to $17,063 million.

Note 3 Acquisitions and Disposals

The Company made a number of acquisitions in 2010 for a total consideration of $3.3 billion.

In March 2010, the Company entered into a partnership in Canada with Value Creation Inc. to develop the Terre de Grace oil sands lease in the Athabasca region. The Company is now the operator and majority partner for the partnership. In 2010, total consideration in relation to the formation of the partnership was $900 million.

In April 2010, the Company acquired 100% of Devon Energy's Gulf of Mexico deepwater properties for $1.8 billion. This included a number of exploration properties, Devon's interest in the major Paleogene discovery Kaskida (giving the Company a 100% interest in the project), four producing assets and one non-producing asset. Goodwill arising from the acquisition amounted to $158 million. As part of the transaction, the Company sold to Devon a 50% stake in its Kirby oil sands interests in Alberta, Canada for $500 million cash and an additional $150 million funding commitment. In addition, the companies formed a 50/50 joint venture, operated by Devon to pursue the development of the interest. The gain on the disposal of the Company's 50% interest in the Kirby oil sands in Alberta, Canada amounted to $633 million.

In September 2010, the Company increased its equity holding in the Norwegian Valhall and Hod fields by acquiring 7.9% interest in the Valhall field and 12.5% in the Hod field from Total. The transaction increased the equity holding in Valhall to 35.95% and Hod to 37.5%. The final purchase consideration was $492 million.

In September 2010, the Company's Alternative Energy business acquired Verenium Corporation's biofuels business, for consideration of $98 million.

In 2009, the Company made no significant acquisitions. The Company made a number of acquisitions in 2008 for a total consideration of $4,070 million. These included the purchase of an additional interest in Chesapeake Energy Corporation's Fayetteville Shale for $1,920 million and Chesapeake Energy Corporation's Arkoma Basin Woodford Shale assets for $1,747 million.

As part of the response to the consequences of the Gulf of Mexico oil spill, in 2010 the Company disposed of various assets as well as announced plans for future disposals. Additionally, in the normal course of business, the Company has sold interests in exploration and production properties, and pipeline interests as well as non-core businesses. See Note 4 for further information relating to assets and associated liabilities held for sale at December 31, 2010.

In July 2010, the Company concluded several agreements to sell upstream assets in the United States, Canada, and Egypt to Apache Corporation. The sales included the Company's Permian Basin assets in Texas and southeast New Mexico, its Western Canada upstream gas assets, and the Western Desert business concessions and East Badr El-din exploration concession in Egypt. Proceeds received by the Company relating to the divestments amounted to $6.3 billion. The pre-tax gain relating to the sales amounted to $3.6 billion.

In August 2010, the Company completed the sale of its entire interest in the Overthrust assets (Painter Complex Gas Plant, Painter Reservoir Unit and Whitney Canyon field and inlet facility) to Merit Energy Company for $198 million. The pre-tax gain relating to the divestment amounted to $175 million.

In October 2010, the Company announced it had reached an agreement with its partner, Hess Corporation (Hess), for the sale of a 20% interest in the Tubular Bells field in the Gulf of Mexico. Hess agreed to acquire the interest from the Company for $40 million and became the operator. The pre-tax loss on disposal amounted to $132 million.

In October 2010, the Company sold its interests in Block 31 of the Permian Basin in West Texas to ConocoPhillips for $605 million. The pre-tax gain relating to the sale amounted to $504 million.

In October 2010, the Company contributed its Cedar Creek II wind energy development asset in exchange for a 50% equity interest in a jointly controlled entity, Cedar Creek II Holdings LLC (Cedar Creek II) and cash of $182 million. In addition, there was a return of capital in the jointly controlled entities Fowler II Holdings LLC and Cedar Creek II Holdings LLC which did not change the Company's percentage interest in either entity.

In December 2010, the Company received its second installment related to previously held interests in its Kazakhstan's Tengiz oil field and Caspian Pipeline Consortium pipeline, which were sold in December 2009. The second installment amounted to $811 million.

During 2010, the Company disposed of various non-strategic pipelines, other marketing assets and terminals in the United States. The more significant transaction included the sale of crude oil storage facilities in Cushing, Oklahoma, and petroleum pipelines in the Houston, Texas area to Magellan Midstream Partners. Proceeds received by the Company relating to these sales amounted to $558 million. The pre-tax gain on these disposals was $290 million.

In 2009, the major disposal transactions were the sale of BP West Java Limited in Indonesia, the sale of the Company's 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of the Company's 46% stake in LukArco, and disposal of various assets in the United States and Australia refining and marketing businesses, all of which resulted in gains. The Company also exchanged interests in a number of fields in the North Sea with BG Group plc. There were no significant disposals in 2008.

Note 4 Assets Held for Sale

As a result of the BP group's disposal program following the Gulf of Mexico oil spill, various assets and associated liabilities have been presented as held for sale in the Company's consolidated balance sheet at December 31, 2010. The carrying amount of the assets held for sale is $4,915 million, with associated liabilities of $308 million. Included within these amounts are the following items, all of which relate to the Company's Exploration and Production segment.

In October 2010, the Company announced that it had reached agreement to sell its recently acquired interests in four mature producing deepwater oil and gas fields in the US Gulf of Mexico to Marubeni Oil and Gas for $650 million, subject to post-closing adjustments. BP acquired the interests in these fields from Devon Energy earlier in 2010 as part of the BP group's wider acquisition of oil and gas interests in the Gulf of Mexico, Brazil and Azerbaijan.

In October 2010, the Company announced that it had reached agreement to sell certain assets in Venezuela, to TNK-BP for $201 million, subject to post closing adjustments. The Venezuelan assets include the Company's interests in the Petroperijá and Boqueron joint ventures. The sale of the Venezuela assets is expected to be completed in the first half of 2011, subject to regulatory and other approvals and conditions.

In November 2010, the Company announced that it had reached agreement to sell its interests in Pan American Energy (PAE), an Argentina based oil and gas company, to Bridas Corporation for $7,060 million. PAE is currently owned by the Company (60%) and Bridas Corporation (40%). The transaction excludes the shares of PAE E&P Bolivia Ltd. The sale is expected to be completed in 2011, subject to closing conditions and government and regulatory approvals.

In December 2010, the Company announced that it had reached agreement to sell its exploration and production assets in Pakistan to United Energy Group Limited for $690 million. The sale is expected to be completed in the first half of 2011, subject to closing conditions and government and regulatory approvals.

During 2010, the Company also announced its intention to divest its interest in the Tuscaloosa fields in Louisiana, the Wattenberg NGL plant in Colorado and its NGL business in Canada.

Disposal proceeds of $4,072 million received in advance of completion of these transactions have been classified as short-term obligations on the Company's consolidated balance sheet. These deposits are presented as proceeds from the sale of property and other assets on the Company's consolidated statement of cash flows.

The major classes of assets and liabilities reclassified as held for sale at December 31, 2010 are as follows:

Millions of Dollars – December 31, 2010		
Assets		
Inventories	$	54
Other current assets		91
Property, plant and equipment		1,872
Investment in affiliates		2,845
Goodwill		53
	$	4,915
Liabilities		
Accounts payable - trade	$	61
Accrual and reserves		247
	$	308

Note 5 Cash Flow Information

The consolidated statement of cash flows provides information about changes in cash and cash equivalents. The Company considers all investments with original maturities of three months or less to be cash equivalents.

Net cash provided by operating activities reflects cash payments for interest and income taxes as follows:

Millions of Dollars - Year Ended December 31		2010		2009		2008
Interest paid	$	788	$	573	$	1,219
Income taxes paid		3,343		3,485		6,855
Federal income tax refunds received		18		493		200

Note 6 Derivative Financial Instruments

The Company uses derivative financial instruments to manage certain exposures to fluctuations in commodity prices as well as for trading purposes. These contracts are used to convert specific sales and purchase contracts from fixed to market prices and to manage exposure to price differences between locations. As part of its energy trading activities, the Company maintains active trading positions in a variety of oil, natural gas and power price contracts. These derivatives are principally comprised of futures contracts, swap agreements, forwards and option contracts.

The Company recognizes all derivative financial instruments that qualify for derivative accounting treatment as either assets or liabilities. These derivative financial instruments are measured at fair value unless they qualify for, and the Company has elected the normal purchase normal sale exemption. For transactions in which the Company elected the normal purchase normal sale exemption, gains and losses are not reflected on the Company's consolidated statement of operations until the settlement dates.

Various adjustments have been made to data in the tables below to conform presentation in all years.

The accounting classification of each category of financial instruments including their fair value and carrying amounts, are presented in the table below. The carrying amount of assets and liabilities in the table below are included in the consolidated balance sheet under the indicated caption.

	2010		**2009** *as Adjusted*	
Millions of Dollars - December 31	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Assets				
Cash and cash equivalents	$ 656	$ 656	$ 520	$ 520
Prepaid expenses and other	2,787	2,787	897	897
Investments, long-term receivables and other	1,215	1,215	252	252
Liabilities				
Short-term obligations	(4,555)	(4,555)	(4,565)	(4,565)
Long-term debt (including current maturities)	(5,786)	(5,974)	(4,491)	(4,729)
Derivative Financial Instruments				
Trading activities				
Natural gas price contracts	368	368	496	496
Power contracts	(42)	(42)	(7)	(7)
Oil price contracts	(139)	(139)	(273)	(273)
Other activities				
Other contracts	(26)	(26)	(12)	(12)

In the above table, initial margin deposits held with the commodity exchanges are included in "Prepaid expenses and other". Total amounts posted with the trading exchanges, including the initial margin, at December 31, 2010 and 2009 with the New York Mercantile Exchange, the Chicago Board of Trade and the Intercontinental Exchange comprises $2,529 million and $1,740 million respectively. At December 31, 2010, for over the counter (OTC) transactions, the Company had $219 million of obligations to return cash collateral and the right to reclaim $135 million of cash collateral. At December 31, 2009, for OTC transactions, the Company had $354 million of obligations to return cash collateral and the right to reclaim $23 million of cash collateral. Only exchange traded derivatives are carried on the consolidated balance sheet net of any cash collateral received or paid.

Included within the 2010 "Investments, long-term receivables and other" balance is the current unlisted investment related to repurchased gas pre-paid bonds. See Note 11 for further information. The 2010 "Investments, long-term receivables and other" balance also reflects the sale, during the year, of the Intercontinental Exchange shares resulting in the realization of gains to the Company of $152 million.

Financial Instruments

Cash and cash equivalents. Cash and cash equivalents are comprised of cash on hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition. The carrying amount reported in the consolidated balance sheet approximates fair value.

Prepaid expenses and other. Prepaid expenses and other includes restricted cash. Items recorded as restricted cash, and included in the table above, include margin deposits with commodity exchanges and the balance of the Deepwater Horizon Oil Spill fund available for eligible claims, in accordance with the Trust agreement. The trust funds are deposited in Government Money Market funds and Government securities. The carrying amount reported in the consolidated balance sheet for these balances approximates fair value.

Investments, long-term receivables and other. Certain investments represent financial instruments. These investments are classified as available-for-sale and are reported at fair value, with unrealized holding gains and losses, net of tax, reported in accumulated other comprehensive income. The fair value of the investments was estimated using quoted prices.

Short-term obligations and long-term debt. The fair value of the Company's non-affiliate debt instruments was estimated using quoted prices, or where such prices were not available, discounted cash flow analyses, based on the Company's current incremental borrowing rates for similar types of borrowing arrangements and maturities. Affiliate debt balances are not included.

Derivative financial instruments. The fair value of derivative financial instruments is based on prices actively quoted, prices sourced from observable data or market corroboration or prices based on models and other valuation methods. Further information regarding the Company's valuation techniques used to measure the fair value of derivative financial instruments is presented in Note 7, Fair Value Measurements.

The carrying amount of derivative financial instruments included in the consolidated balance sheet is as follows:

Millions of Dollars - December 31	2010	2009 as Adjusted
Prepaid expenses and other	$ 1,439	$ 1,967
Investments, long-term receivables and other	2,959	2,814
Accrued liabilities	(2,515)	(2,888)
Accruals and reserves	(1,722)	(1,690)

Derivatives included on the Consolidated Statement of Operations

Changes in the fair values of the Company's derivative instruments (both assets and liabilities) are presented in the consolidated statement of operations. Gains and losses are included either within sales and operating revenue or within purchases in the consolidated statement of operations depending upon the nature of the activity and the type of contract involved. The following table details the net unrealized and realized gains (losses) recognized from the Company's derivative financial instruments and where these components are recorded on the Company's consolidated statement of operations for the years ended December 31, 2010 and 2009.

Millions of Dollars – December 31	2010		2009 as Adjusted	
	Sales and Other Operating Revenue	Purchases	Sales and Other Operating Revenue	Purchases
Realized and unrealized gain (loss)				
Natural gas price contracts	$ 6,088	$ (1,542)	$ 7,004	$ (1,299)
Power contracts	46	(42)	35	(63)
Oil price contracts	30,512	(50,654)	20,467	(37,945)
Other contracts	106	(73)	1,423	(1,336)
Total	$ 36,752	$ (52,311)	$ 28,929	$ (40,643)

Derivative Financial Instruments Included on the Consolidated Balance Sheet

All derivative financial instruments are reflected as either assets or liabilities, at fair value, in the Company's consolidated balance sheet at December 31, 2010 and 2009. In the table below, these fair values are presented on a gross basis. As such, the amounts do not reflect any offsetting for contracts that are subject to master netting arrangements.

Millions of Dollars		**Prepaid Expenses and Other**	**Investments, Long-term Receivables and Other**	**Accrued Liabilities**	**Accruals and Reserves**	**Asset (Liability)**
December 31, 2010						
Natural gas	Asset	$ 24,241	$ 3,078	$ 702	$ 285	$ 28,306
	Liability	(23,248)	(437)	(2,363)	(1,890)	(27,938)
Power	Asset	4,665	231	307	101	5,304
	Liability	(4,464)	(75)	(573)	(234)	(5,346)
Oil	Asset	472	219	5,850	532	7,073
	Liability	(241)	(57)	(6,371)	(543)	(7,212)
Other	Asset	14	-	444	26	484
	Liability	-	-	(510)	-	(510)
December 31, 2009 *as Adjusted*						
Natural gas	Asset	$ 20,423	$ 2,926	$ 1,252	$ 586	$ 25,187
	Liability	(19,110)	(438)	(3,125)	(2,018)	(24,691)
Power	Asset	3,865	256	426	78	4,625
	Liability	(3,614)	(87)	(708)	(223)	(4,632)
Oil	Asset	453	189	4,367	381	5,390
	Liability	(163)	(54)	(4,995)	(451)	(5,663)
Other	Asset	196	37	58	28	319
	Liability	(82)	(15)	(163)	(71)	(331)

The following table summarizes the Company's material exposures resulting from outstanding commodity derivative contracts, excluding those derivatives that qualified for the normal purchase and normal sales exception as of December 31, 2010 and December 31, 2009.

December 31	**2010**	**2009**	
		(millions)	**Unit**
		as Adjusted	
Natural gas price contracts	1,194	37	mmbtu
Power contracts – electricity	(6)	8	mwh
Oil price contracts	146	4	bbl
Other contracts	(11)	4	bbl
Other contracts	(8)	-	mmbtu

Credit Risk

Credit risk relates to the risk of loss resulting from the non performance or non payment by the Company's counterparties related to their contractual obligations with us. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company also has credit risk if counterparties are unable to provide collateral or post margin. The Company's credit risk is monitored and managed through credit approvals, routine monitoring of counterparties' credit limits and their overall credit ratings; limiting the Company's marketing and optimization activities with high risk counterparties; margin collateral or prepayment arrangements; and payment netting arrangements, or master netting arrangements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

The Company continually monitors the exposure and the creditworthiness of its counterparties. Trade and other receivables are carried at the original invoice amount, less allowances for doubtful receivables in the amounts of $131 million and $111 million as of December 31, 2010 and 2009, respectively. Provisions are made when there is objective evidence that the Company will be unable to recover balances in full. Balances are written off when the probability of recovery is assessed as remote.

Use of Collateral

Certain of the Company's derivative financial instruments contain credit-contingent provisions that require the Company to maintain its current credit rating or higher from each of the major credit rating agencies. The Company uses margin deposits, prepayments and letters of credit as credit support with and from the Company's counterparties for commodity procurement and risk management activities. The aggregate fair value of the Company's derivative liabilities with credit-contingent provisions as of December 31, 2010, was $736 million for which the Company has posted collateral of $585 million. At December 31, 2010, the Company was rated A minus by Standard and Poor's and Baa1 by Moody's. If Standard and Poor's/Moody's were to reduce this credit rating to BBB/Baa2, the additional collateral that could be required to be posted for these derivative contracts would amount to approximately $70 million. Were Standard and Poor's/Moody's to further reduce the credit rating to BBB minus/Baa3, the additional collateral that could be required to be posted for these derivative contracts would amount to approximately $120 million.

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company's business activities may not be available. The Company's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central BP treasury function. The Company pools cash surpluses to BP's treasury, which will then arrange to fund the Company's or other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing BP's overall net currency positions. Following the Gulf of Mexico oil spill, the Company was required to make substantial cash payments in connection with the oil spill and also experienced increased requirements during the year to post letters of credit to collateralize a number of environmental liabilities. See Commitments and Guarantees below. The Company, through BP, also has access to substantial amounts of undrawn borrowing facilities. See Note 11.

Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The primary commodity price risks that the Company is exposed to include oil, natural gas and power prices that could adversely affect the value of the Company's assets, liabilities or expected future cash flows. The Company enters into derivatives in a well-established entrepreneurial trading operation and measures market risk exposure arising from its trading positions using value-at-risk techniques.

Commitments and Guarantees

At December 31, 2010, the Company's contractual commitments under throughput and take or pay arrangements amounted to $6,886 million.

In addition to the Company's $15 billion obligation to fund the Deepwater Horizon Oil Spill trust (see Note 2), at December 31, 2010 the Company had also committed to a $500 million 10-year research program to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico. During 2010, $40 million relating to this program was recognized in the Company's consolidated statement of operations. The $500 million is expected to be spent evenly over the 10-year period.

As part of the Company's normal business operations, the Company enters into various agreements providing, or otherwise arranging, financial or performance assurance to third parties on behalf of its subsidiaries in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees and standby letters of credit for power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of various facilities. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Certain of these guarantees and indemnifications have no stated or notional amounts or limitation to the maximum potential future payments. Liabilities for all commitments that are guaranteed are recorded on the consolidated balance sheet. The Company does not expect any material loss as a result of these guarantees.

At December 31, 2010, the Company posted letters of credit totaling $1,694 million. Of this total, $960 million pertains to trading activity. The maximum amount of the Company's obligation for guarantees of certain equity investments at December 31, 2010, was $743 million. Payment would be required if a joint venture defaults on its debt obligations.

In order to provide liquidity for the Company's savings plans, the Company agreed to advance the savings plans up to $200 million. Amounts borrowed by the savings plans under the revolving loan facility do not bear interest and are repayable within three days. At December 31, 2010 and 2009, there were no amounts outstanding under the agreement.

The purchase of third party insurance is generally limited to situations where insurance is required for legal or contractual reasons. For certain operations, the Company purchases insurance coverage from a subsidiary of BP.

Note 7 Fair Value Measurements

The Company uses fair value to measure certain of its assets, liabilities and expenses in its consolidated financial statements. Fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., the exit price). Generally, the determination of fair value requires the use of significant judgment and different approaches and models under varying circumstances. Under a market based approach, the Company considers prices of similar assets, consults with brokers and experts or employs other valuation techniques. Under an income based approach, the Company generally estimates future cash flows and then discounts them at a risk adjusted rate. The Company's most significant fair value measurements represent the valuation of its derivative assets and liabilities, which are measured on a recurring basis (each reporting period) and measurements of impairments and acquired assets on a nonrecurring basis. The Company primarily applies the market approach and income approach for recurring fair value measurements (primarily the Company's derivative assets and liabilities) using the best available information.

The Company primarily utilizes the income approach for nonrecurring fair value measurements such as impairments of the Company's assets as market prices for similar assets may not be readily available and may not incorporate the expected future returns from the Company's assets. The Company utilizes valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. The Company classifies fair value balances based on the observability of those inputs.

US GAAP establishes a fair value hierarchy which classifies fair value measurements from Level 1 through Level 3 based upon the inputs used to measure fair value:

Level 1 — Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 — Pricing inputs include significant inputs that are generally less observable or from unobservable sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

The valuation techniques used by the Company to measure fair value are summarized as follows:

Exchange traded derivatives are valued using unadjusted closing prices provided by the exchange as of the balance sheet date. These derivatives are classified as Level 1 in the fair value hierarchy. Over the counter financial swaps and physical commodity purchase and sale contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are classified as Level 2 in the fair value hierarchy.

In certain less liquid markets or for longer term contracts, forward prices are not as readily available. In these circumstances, over the counter financial swaps and physical commodity purchase and sale contracts are valued using internally developed methodologies that consider historical relationships among various commodities that result in management's best estimate of fair value. These contracts are classified as Level 3 in the fair value hierarchy.

Exchange traded financial options are valued using exchange closing prices and are classified as Level 1 in the fair value hierarchy. Financial Over The Counter (OTC) and physical commodity options are valued using industry standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic factors. The degree to which these inputs are observable in the forward markets determines whether the option is classified as Level 2 or Level 3 in the fair value hierarchy.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's derivative financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of significance for a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities within the fair value hierarchy levels. Various adjustments have been made to data in the tables below to conform presentation in all years.

Millions of Dollars	Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Observable (Level 2)	Unobservable (Level 3)	Total
December 31, 2010				
Assets				
Natural gas price contracts	$ 722	$ 25,977	$ 1,607	$ 28,306
Power contracts	-	5,249	55	5,304
Oil price contracts	5,924	1,142	7	7,073
Other contracts	32	452	-	484
Total assets	6,678	32,820	1,669	41,167
Liabilities				
Natural gas price contracts	(1,235)	(25,766)	(937)	(27,938)
Power contracts	-	(5,292)	(54)	(5,346)
Oil price contracts	(6,115)	(1,097)	-	(7,212)
Other contracts	(45)	(465)	-	(510)
Total liabilities	(7,395)	(32,620)	(991)	(41,006)
Net (Liabilities) Assets	$ (717)	$ 200	$ 678	$ 161

Millions of Dollars	Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Observable (Level 2)	Unobservable (Level 3)	Total
December 31, 2009 *as Adjusted*				
Assets				
Natural gas price contracts	$ 999	$ 22,974	$ 1,214	$ 25,187
Power contracts	-	4,625	-	4,625
Oil price contracts	3,828	1,529	33	5,390
Other contracts	-	316	3	319
Total assets	4,827	29,444	1,250	35,521
Liabilities				
Natural gas price contracts	(1,135)	(22,497)	(1,059)	(24,691)
Power contracts	-	(4,632)	-	(4,632)
Oil price contracts	(4,074)	(1,575)	(14)	(5,663)
Other contracts	-	(328)	(3)	(331)
Total liabilities	(5,209)	(29,032)	(1,076)	(35,317)
Net (Liabilities) Assets	$ (382)	$ 412	$ 174	$ 204

The following table presents a reconciliation of the net beginning and ending balances recorded for derivative financial instruments classified as Level 3 in the fair value hierarchy for the years ended December 31, 2010 and 2009.

Millions of Dollars	2010	2009
Balance at January 1	$ 174	$ 51
Total net realized and unrealized gain		
Included in net (loss) income		
Operating revenues	569	173
Purchases, issuances and settlements:		
Settlements	(11)	(5)
Transfers into/or out of Level 3:		
Transfers into Level 3	(31)	-
Transfers out of Level 3	(23)	(45)
Balance at December 31	$ 678	$ 174
Change in unrealized gains relating to instruments still held at end of period	$ 584	$ 176

The Company transfers amounts among levels of the fair value hierarchy as of the end of each period. There were no significant transfers into/out of Level 1 during the years ended

December 31, 2010, 2009 and 2008. There were no significant transfers into Level 3 for the years ended December 31, 2010, 2009 and 2008. Transfers out of Level 3 into Level 2 were due to changes in market liquidity.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

During 2010 property, plant and equipment with a carrying amount of $2,212 million was written down to its fair value of $1,215 million, resulting in a before-tax loss of $997 million primarily related to the $501 million impairment of a Gulf of Mexico asset and fair value assessments made prior to the sale of oil and gas properties in the Gulf of Mexico and onshore North America of $310 million and $80 million, respectively. The fair values were determined based on bids received from prospective buyers and from internal cash-flow models consistent with those used by the Company to evaluate cash flows of other assets of a similar nature. During 2009, property, plant and equipment with a carrying amount of $290 million was written down to its fair value of $98 million, resulting in a before tax loss of $192 million. The fair values were determined from internal cash-flow models, using discount rates consistent with those used by the Company to evaluate cash flows of other assets of a similar nature (a Level 3 fair value measurement).

The Company had $5,759 million and $6,066 million of goodwill on the consolidated balance sheet at year-end 2010 and 2009, respectively. During 2009, goodwill assigned to Refining and Marketing West Coast Fuels Value Chain, with a carrying amount of $1,795 million, was written down to its implied fair value of zero, resulting in an impairment charge of $1,795 million. Since there was limited market-based data available, fair value of the reporting unit was principally based on a discounted cash flow model (a Level 3 fair value measurement).

Note 8 Inventories

Millions of Dollars - December 31		**2010**		**2009**
Crude oil, natural gas and other petroleum products	$	2,517	$	3,152
Chemical products		182		24
Materials, supplies and other		1,120		1,283
	$	3,819	$	4,459

As a result of the use of the LIFO inventory valuation method, some inventories are reported in the consolidated balance sheet at amounts less than current cost. Inventories carried under the LIFO method represented approximately 48 percent of total year-end inventory carrying values in 2010 and approximately 35 percent of total year-end inventory carrying values in 2009. It is estimated that inventories would have been approximately $9,137 million and $7,969 million higher than reported at December 31, 2010 and 2009, respectively, if the quantities valued on the LIFO basis were instead valued at current prices. The percentage increase in total inventory carried under the LIFO method is due to the decrease of non-LIFO inventory related to the BPAGL deconsolidation. See Note on Organization and Accounting Changes.

During 2010 and 2009, certain inventory volumes decreased resulting in the liquidation of LIFO inventory quantities. In 2010 the inventory liquidated was carried at lower costs as compared to 2010 purchases. In 2009 the inventory liquidated was carried at higher costs prevailing in prior years as compared with cost of 2009 purchases. The effects of these liquidations were an increase to income before income taxes for the year ended December 31, 2010 by $200 million and a decrease in income before income taxes for the year ended December 31, 2009 by $270 million.

Note 9 Investments in Affiliates and Other

The Company conducts portions of its business through investments in companies accounted for using the equity method. The equity accounted entities are primarily engaged in exploration and refining in North America, exploration and production in South America, transportation of crude oil and petroleum products in the United States and petroleum and chemical operations in Asia. The following table summarizes financial information for the Company's equity accounted entities as reported by these entities.

	Investee		
Millions of Dollars - December 31	**2010**	**2009**	**2008**
Current assets	$ 6,682	$ 5,934	
Other assets	22,838	21,762	
Current liabilities	2,602	2,721	
Other liabilities	4,592	3,664	
Net assets	$ 22,324	$ 21,311	
Millions of Dollars – Year ended December 31			
Total revenues	$ 13129	$ 11,039	$ 12,902
Income before income taxes	2,740	2,365	1,833
Net income	1,628	1,745	1,031

The following table presents the Company's interests in the equity accounted entities and other investments

	Company's Share		
Millions of Dollars - December 31	**2010**	**2009**	**2008**
Carrying value of equity investments	$ 6,035	$ 8,421	
Other investments and loans	6,009	384	
Total investments in affiliates	$ 12,044	$ 8,805	
Millions of Dollars – Year ended December 31			
Net income from equity investments	$ 915	$ 969	$ 576

Dividends received from these investments amounted to $444 million in 2010, $370 million in 2009 and $371 million in 2008.

Accounts and notes receivable in the consolidated balance sheet included $109 million and $229 million at December 31, 2010 and 2009, respectively, of amounts due from equity investees. Accrued liabilities, and accruals and reserves include the current and long term portion of $2,661 million and $2,571 million at December 31, 2010 and 2009, respectively, of amounts due to equity investees. Included in accrued liabilities and accruals and reserves at December 31, 2010 and 2009 is the current and long-term portion of $2,583 million and $2,509 million, respectively, payable to the Sunrise Oil Sands Partnership. The amount is payable on or before December 31, 2015 as called by the joint venture to fund its capital expenditures.

At December 31, 2010, the total Investments in affiliates balance increased by $3.2 billion as compared to December 31, 2009. The increase is primarily attributable to the dilution of the Company's ownership in BPAGL from 75 percent to 49 percent and the subsequent conversion of its ownership interest to preferred shares ($5.7 billion). The resulting increase to the Company's converted investment in BPAGL was recognized as a $5.4 billion capital contribution. This capital contribution reflects a transfer of the controlling interest in BPAGL to another BP group subsidiary. See Organization and Accounting Changes. This increase is partially offset by the reclassification of the Company's interests in Pan American Energy and other joint ventures to assets held for sale ($2.6 billion). See Note 4 for further information.

The Company's interest in equity accounted entities at December 31, 2010 and at December 31, 2009 are listed in the table below.

Millions of Dollars – December 31	Percent owned	2010	2009
Investee			
Sunrise Oil Sands Partnership	50.00 %	$ 2,691	$ 2,626
BP-Husky Refining LLC	50.00	946	784
Pan American Energy LLC	60.00	465	2,794
Destin Pipeline Company LLC	66.67	187	197
Fowler Ridge Wind Farm LLC	50.00	159	171
Cleopatra Gas Gathering Company LLC	54.00	153	145
Caesar Oil Pipeline Company LLC	56.00	148	154
Proteus Oil Pipeline Company LLC	75.00	145	151
Watson Cogeneration Company	51.00	145	179
Endymion Oil Pipeline Company LLC	75.00	142	148
Okeanos Gas Gathering Company LLC	66.67	121	128
Cedar Creek II LLC	50.00	117	-
Unimar LLC	50.00	113	115
Fowler Ridge II Wind Farm LLC	50.00	33	211
Other		470	618
Total equity investments in affiliates		$ 6,035	$ 8,421

Note 10 Litigation and Contingencies

Proceedings and investigations relating to the Gulf of Mexico oil spill

The Company, BP Exploration & Production Inc. (BP E&P) and various other BP entities (collectively referred to as BP) are among the companies named as defendants in more than 400 private civil lawsuits resulting from the April 20, 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill (the Incident) and further actions are likely to be brought. BP E&P is lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico, where the Deepwater Horizon was deployed at the time of the Incident, and holds a 65% working interest.

The other working interest owners are Anadarko Petroleum Company and MOEX Offshore 2007 LLC. The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean, Ltd. (Transocean), sank on April 22, 2010. The pending lawsuits and/or claims arising from the Incident have been brought in US federal and state courts. Plaintiffs include individuals, corporations and governmental entities and many of the lawsuits purport to be class actions. The lawsuits assert, among others, claims for personal injury in connection with the Incident itself and the response to it, and wrongful death, commercial or economic injury, breach of contract and violations of statutes. The lawsuits seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, claims for environmental damage, remediation costs, injunctive relief, treble damages and punitive damages. Purported classes of claimants include residents of the states of Louisiana, Mississippi, Alabama, Florida, Texas, Tennessee, Kentucky, Georgia and South Carolina, property owners and rental agents, fishermen and persons dependent on the fishing industry, charter boat owners and deck hands, marina owners, gasoline distributors, shipping interests, restaurant and hotel owners and others who are property and/or business owners alleged to have suffered economic loss.

Shareholder derivative lawsuits have also been filed in US federal and state courts against various current and former officers and directors of BP alleging, among other things, breach of fiduciary duty, gross mismanagement, abuse of control and waste of corporate assets. Purported class action lawsuits have also been filed in US federal courts against BP entities and various current and former officers and directors alleging securities fraud claims and violations of the Employee Retirement Income Security Act (ERISA). In addition, the Company has been named in several lawsuits alleging claims under the Racketeer-Influenced and Corrupt Organizations Act (RICO). In August 2010, many of the lawsuits pending in federal court were consolidated by the Federal Judicial Panel on Multidistrict Litigation into two multi-district litigation proceedings, one in federal court in Houston for the securities, derivative and ERISA cases and another in federal court in New Orleans for the remaining cases. Since late September, most of the Deepwater Horizon related cases have been pending before these courts.

On February 18, 2011, certain Transocean affiliates filed a third party complaint against the Company , the US government, and other corporations involved in the Incident, thereby naming those entities as formal parties in Transocean's Limitation of Liability action pending in federal court in New Orleans. Under the OPA 90, BP E&P has been designated as one of the 'responsible parties' for the oil spill resulting from the Incident. Accordingly, BP E&P is one of the parties that the US government alleges is financially responsible for the clean-up of the spill and for economic damages as provided by the OPA 90. In addition, pursuant to the OPA 90, the US Coast Guard has requested reimbursement from the Company and the other responsible parties for its costs of responding to the Incident, and the Company has paid all amounts due as of the date hereof. Continuing requests for cost reimbursement are expected from the US Coast Guard and other governmental authorities. In addition, the Company is participating with federal and state trustees in a co-operative assessment of potential natural resource damages associated with the spill. Under the OPA 90, the US government alleges that BP E&P is one of the parties financially responsible for paying the reasonable assessment costs incurred by these trustees as well as natural resource damages that result from the Incident.

BP E&P has established and committed to fund the Deepwater Horizon Oil Spill Trust, a $20 -billion trust fund to pay costs and satisfy legitimate claims. BP E&P contributed $5 billion to the trust fund in 2010. This will be supplemented by additional payments of $1.25 billion per quarter until a total of $20 billion has been paid into the trust fund. While the trust fund is building, BP E&P has pledged collateral consisting of an overriding royalty interest in oil and gas production from certain assets in the Gulf of Mexico sufficient at any time to secure the difference between the amounts deposited as of that date and $20 billion. The establishment of this trust does not represent a cap on the Company's liabilities, and the Company does not admit to a liability of this amount. The trust fund will pay claims administered by the GCCF, state and local government claims resolved by the Company, final judgments, settlements, state and local response costs, and natural resource damages and related costs. Payments from the trust fund will be made upon adjudication or resolution of claims or the final determination of other costs covered by the trust fund.

There will be a sunset on the trust fund, and funds, if any, remaining once the claims process has been completed will revert to BP E&P.

The Company is subject to a number of investigations related to the Incident by numerous agencies of the US government. On April 27, 2010, the US Coast Guard and the Minerals Management Service (renamed the Bureau of Ocean Energy Management, Regulation and Enforcement in June 2010) convened a joint investigation of the Incident by establishing a Marine Board of Investigation (Marine Board of Investigation) aimed at determining the causes of the Incident and recommending safety improvements. The Company was designated as one of several Parties in Interest in the investigation.

On May 21, 2010, President Obama signed an executive order establishing the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) to examine and report on, within six months of the date of the Commission's first meeting, the relevant facts and circumstances concerning the causes of the Gulf of Mexico oil spill incident and develop options for guarding against, and mitigating the impact of, oil spills associated with offshore drilling, taking into consideration the environmental, public health, and economic effects of such options. On January 11, 2011, the National Commission published its final report on the causes of the Incident and its recommendations for policy and regulatory changes for offshore drilling. On February 17, 2011, the National Commission's Chief Counsel published a separate report on his investigation that provides additional information about the causes of the Incident. The National Commission ceased operations on March 11, 2011. In a report dated March 20, 2011, the Joint Investigation Team (JIT) for the Marine Board of Investigation issued the Final Report of the Forensic Examination of the *Deepwater Horizon* Blowout Preventer (BOP) prepared by Det Norske Veritas (Report). The Company has cooperated fully with the JIT investigation. The Report concludes that the position of the drill pipe against the blind shear rams was the primary cause of the BOP not functioning as intended. The Company continues to review the Report and agrees with the Report's recommendation that additional testing should be completed to provide a more comprehensive view of why the BOP failed.

On July 7, 2010, the US Chemical Safety and Hazard Investigation Board (CSB) informed BP of its intent to conduct an investigation of the Incident. The investigation is focused on the April 20, 2010 explosions and fire, and not the resulting oil spill or response efforts. The CSB is expected to issue within two years several investigation reports that will seek to identify the alleged root cause(s) of the Incident, and recommend improvements to the Company and industry practices and to regulatory programs to prevent recurrence and mitigate potential consequences. Also, at the request of the Department of the Interior, the National Academy of Engineering/National Research Council established a Committee (Committee) to examine the performance of the technologies and practices involved in the probable causes of the explosion, including the performance of the blowout preventer and related technology features, and to identify and recommend available technology, industry best practices, best available standards, and other measures in the US and around the world related to oil and gas deepwater exploratory drilling and well completion to avoid future occurrence of such events. On November 17, 2010, the Committee publicly released its interim report setting forth the committee's preliminary findings and observations on various actions and decisions including well design, cementing operations, well monitoring, and well control actions. The interim report also considers management, oversight, and regulation of offshore operations. The Company expects that the Committee will issue its final report that presents the Committee's final analysis, including findings and/or recommendations, by June 1, 2011 (a pre-publication version of report), with further review and a final published version to follow by December 30, 2011.

A second, unrelated National Academies' Committee will be looking at the methodologies available for assessing spill impacts on ecosystems in the Gulf of Mexico, and a summary of the known effects of the spill, the impacts in the context of stresses from other human activities in the Gulf, and identification of research and monitoring needs to more fully understand the effects of the spill and gauge progress towards recovery and restoration.

A third National Academies' Committee will be studying methods for assessing the effectiveness of safety and environmental management systems (SEMS) established by offshore oil and gas operators. The Committee will be preparing an interim report that will identify a range of assessment means and the pros and cons of each; the Company understands that the Committee plans to issue the interim report in April 2011. The Company also understands that the Committee will issue a final report of recommendations that will focus on assessing human and organizational factors, and that the Committee expects to complete the final report of recommendations by December 30, 2011.

On June 14, 2010, the US Coast Guard initiated an Incident Specific Preparedness Review (ISPR) to examine the implementation and effectiveness of the response and recovery operations relating to the spill.

On March 18, 2011, the Coast Guard ISPR team released its final report capturing lessons learned from the incident as well as making recommendations on how to improve future oil spill response and recovery efforts.

Additionally, representatives of the Company and various BP entities have appeared before multiple committees of the US Congress that have been conducting inquiries into the Incident. The Company has provided documents and written information in response to requests by these committees and will continue to do so.

On June 1, 2010, the US Department of Justice (DoJ) announced that it is conducting an investigation into the Incident encompassing possible violations of US civil or criminal laws. The United States filed a civil complaint against BP E&P and others on December 15, 2010. The complaint seeks a declaration of liability under the OPA 90 and civil penalties under the Clean Water Act. Paragraph 92 of the complaint sets forth a purported 'reservation of rights' on behalf of the United States to amend the complaint or file additional complaints seeking various remedies under various laws and regulations, including but not limited to eight specifically mentioned federal statutes. Paragraph 92 of the complaint likewise contains a similar 'reservation of rights' regarding the conduct of 'administrative proceedings' under 'the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1301 et seq., and the Federal Oil and Gas Royalty Management Act, 30 U.S.C. §§ 1701 et seq.'

Citizens groups have also filed either lawsuits or notices of intent to file lawsuits seeking civil penalties and injunctive relief under the Clean Water Act and other environmental statutes. The DoJ announced on March 7, 2011 that it created a unified task force of federal agencies, led by the DoJ Criminal Division, to investigate the Gulf of Mexico incident. Other US federal agencies may commence investigations relating to the Incident. The SEC and DoJ are investigating securities matters arising in relation to the Incident.

The State of Alabama has filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, as a result of the Incident. The State of Louisiana has filed a lawsuit to declare various BP entities (as well as other entities) liable for removal costs and damages (economic and environmental, including natural resource damages) under federal and state law, and to recover civil penalties and State's response costs under state law. It is possible that the States of Mississippi, Florida, Texas or other states and/or local governments, such as coastal municipalities also may initiate investigations and bring civil or criminal actions seeking damages, penalties and fines for violating state or local statutes. The Louisiana Department of Environmental Quality has issued an administrative order seeking injunctive relief and environmental civil penalties under state law, and several local governments in Louisiana have filed suits under state wildlife statutes seeking penalties for damage to wildlife as a result of the spill. On December 10, 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several State environmental statutes.

On September 15, 2010, three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo, and Tamaulipas) filed lawsuits in federal court in Texas against the Company and several BP entities. These lawsuits allege that the oil spill harmed their tourism, fishing, and commercial shipping industries (resulting in, among other things, diminished tax revenue), damaged natural resources and the environment, and caused the states to incur expenses in preparing a response to the oil spill.

Gulf of Mexico Oil Spill – Contingent Liabilities

As a consequence of the Gulf of Mexico oil spill, the Company has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 14.

The Company has provided for its best estimate of certain claims under the Oil Pollution Act of 1990 (OPA 90) that will be paid through the $20 -billion trust fund. It is not possible, at this time, to measure reliably any other items that will be paid from the trust fund, namely any obligation in relation to Natural Resource Damages claims, and claims asserted in civil litigation, nor is it practicable to estimate their magnitude or possible timing of payment.

Natural resource damages resulting from the oil spill are currently being assessed. The Company and the federal and state trustees are collecting extensive data in order to assess the extent of damage to wildlife, shoreline, near shore and deepwater habitats, and recreational uses, among other things. Because the affected areas and their uses vary by seasons, the Company anticipates that it will need at least a full year, and perhaps materially longer, after the initial oil impacts to gain an understanding of the natural resource damages. In addition, if early restoration projects are undertaken, these projects could mitigate the total damages resulting from the incident. Accordingly, until the size, location and duration of the impact have been determined and the effects of early restoration projects are assessed, or other actions such as potential future settlement discussions occur, it is not possible to obtain a range of outcomes or to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims.

The Company is named as a defendant in more than 400 civil lawsuits brought by individuals, corporations and governmental entities in US federal and state courts resulting from the Gulf of Mexico oil spill. Additional lawsuits are likely to be brought. The lawsuits assert, among others, claims for personal injury in connection with the incident itself and the response to it, and wrongful death, commercial or economic injury, breach of contract and violations of statutes. The lawsuits, many of which purport to be class actions, seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, claims for environmental damage, remediation costs, injunctive relief, treble damages and punitive damages. These pending lawsuits are at the very early stages of proceedings and most of the claims have been consolidated into one of two multi-district litigation proceedings. A trial of liability issues in the pending multi-district litigation is currently scheduled for February 2012. Damage issues will be scheduled for trial thereafter. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears, or other actions such as possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liability.

Therefore no amounts have been recorded for these items as of December 31, 2010.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, for those relating to the Clean Water Act. It is also not possible to reliably estimate legal fees beyond two years. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from the Company. For example, a complaint filed by the United States sought to reserve the ability to seek penalties and other relief under a number of other laws. Given the large number of claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed.

Therefore no amounts have been provided for these items.

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in the future in relation to the incident.

Gulf of Mexico Oil Spill – Contingent Assets

The Company is the operator of the Macondo well and holds a 65% working interest, with the remaining 35% interest held by two co-owners, Anadarko Petroleum Corporation (APC) and MOEX Offshore 2007 LLC (MOEX). Under the Operating Agreement, MOEX and APC are responsible for reimbursing BP for their proportionate shares of the costs of all operations and activities conducted under the Operating Agreement. In addition, the parties are responsible for their proportionate shares of all liabilities resulting from operations or activities conducted under the Operating Agreement, except where liability results from a party's gross negligence or willful misconduct, in which case that party is solely responsible. The Company does not believe that it has been grossly negligent nor has it engaged in willful misconduct under the terms of the Operating Agreement or at law.

As of December 31, 2010, $6 billion had been billed to the co-owners, which the Company believes to be contractually recoverable. Billings to co-owners are based upon costs incurred to date rather than amounts provided in the period. As further costs are incurred, the Company believes that certain of the costs will be billable to the Company's co-owners under the Operating Agreement.

The Company's co-owners have each written to the Company indicating that they are withholding payment in light of the investigations surrounding, and pending determination of the root causes of, the incident. In addition, APC has publicly accused the Company of having been grossly negligent and stated it has no liability for the incident, both of which claims the Company refutes and intends to challenge in any legal proceedings. There are also audit rights concerning billings under the Operating Agreement which may be exercised by APC and MOEX, and which may or may not lead to an adjustment of the amount billed. The Company may ultimately need to enforce its rights to collect payment from the co-owners through an arbitration proceeding as provided for in the Operating Agreement. There is a risk that amounts billed to co-owners may not ultimately be recovered should the Company's co-owners be found not liable for these costs or be unable to pay them.

The Company believes that it has a contractual right to recover the co-owners' shares of the costs incurred, however, no recovery amounts have been recognized in the consolidated financial statements as of December 31, 2010.

<u>Other Contingent Liabilities</u>

There were contingent liabilities at December 31, 2010 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities.

In the normal course of the Company's business, legal proceedings are pending or may be brought against the Company arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, premises-liability claims, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. The Company believes that the impact of these legal proceedings on the Company's results of operations, liquidity and or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield Company (Atlantic Richfield), a subsidiary of the Company, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programs, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defenses. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, the Company believes that the impact of these lawsuits on the Company's results, financial position or liquidity will not be material.

The Company files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the Company's income tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the estimated accrual has been provided in these accounts in accordance with the Company's accounting policies. The Company does not anticipate that there will be any material impact upon the Company's results of operations, financial position and liquidity.

The Company is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the Company to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the Company or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the Company may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the Company's accounting policies. While the amounts of future costs could be significant and could be material to the Company's results of operations in the period in which they are recognized, it is not practical to estimate the amounts involved. The Company does not expect these costs to have a material effect on the Company's financial position or liquidity.

The Company also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. The Company believes that the impact of any reasonably foreseeable changes to these provisions on the Company's results of operations, financial position and liquidity will not be material.

From October 25, 2007 to October 23 2010, the Company was subject to oversight by an independent monitor, who had authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission (CFTC) regulations and to recommend corrective action. The appointment of the independent monitor was a condition of the deferred prosecution agreement (DPA) entered into with the DoJ on October 25, 2007 relating to allegations that the Company manipulated the price of February 2004 Texas Eastern Products Pipeline (TET) physical propane and attempted to manipulate the price of TET propane in April 2003 and the companion consent order with the CFTC, entered the same day, resolving all criminal and civil enforcement matters pending at that time concerning propane trading by BP Products North America Inc. (BP Products). The DPA required the Company and certain of its affiliates' continued co-operation with the US government's investigation and prosecution of the trades in question, as well as other trading matters that may arise.

The DPA had a term of three years but could be extended by two additional one-year periods, and contemplated dismissal of all charges at the end of the term following the DoJ's determination that the Company has complied with the terms of the DPA. The initial three year term has expired and the DoJ's motion to dismiss the action underlying the DPA was granted on January 31, 2011.

Investigations into BP's trading activities continue to be conducted from time to time. The US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) are currently investigating several Company entities regarding trading in the next-day natural gas market at Houston Ship Channel during October and November 2008. The FERC Office of Enforcement staff notified BP on November 12, 2010 of their preliminary conclusions relating to alleged market manipulation in violation of 18 C.F.R. Sec. 1c.1. The FERC staff will determine whether to pursue the investigation, to close the investigation, or to seek authority to pursue resolution by settlement. On November 30, 2010, CFTC Enforcement staff also provided BP with a notice of intent to recommend charges based on the same conduct alleging that BP engaged in attempted market manipulation in violation of Section 6(c), 6(d), and 9(a)(2) of the Commodity Exchange Act.

The Company submitted responses to both notices on December 23, 2010 providing a detailed response that it did not engage in any inappropriate or unlawful activity. Private complaints, including class actions, were also filed against BP Products and affiliates alleging propane price manipulation. The complaints contained allegations similar to those in the CFTC action as well as of violations of federal and state antitrust and unfair competition laws and state consumer protection statutes and unjust enrichment. The complaints sought actual and punitive damages and injunctive relief. Settlement in both groups of the class actions (the direct and indirect purchasers) has received final court approval. Two independent lawsuits from class members who opted out of the direct purchaser settlement are still pending.

On March 23, 2005, an explosion and fire occurred in the isomerization unit of BP Products' Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. BP Products has resolved all civil injury claims arising from the March 2005 incident.

In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued a report on the incident. The report contained recommendations to the Texas City refinery and to the board of directors of BP. In May 2007, the Company responded to the CSB's recommendations. The Company and the CSB will continue to discuss the Company's responses with the objective of the CSB's agreeing to close out its recommendations.

On October 25, 2007, the DoJ announced that it had entered into a criminal plea agreement with BP Products related to the March 2005 explosion and fire. On February 4, 2008, BP Products pleaded guilty, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US Clean Air Act (CAA) and on March 12, 2009, the court accepted the plea agreement. In connection with the plea agreement, BP Products paid a $50 -million criminal fine and was sentenced to three years' probation which is set to expire on March 12, 2012. Compliance with a 2005 US Occupational Safety and Health Administration (OSHA) settlement agreement (2005 Agreement) and a 2006 agreed order entered into by BP Products with the Texas Commission on Environmental Quality (TCEQ) are conditions of probation.

The Texas Office of Attorney General, on behalf of TCEQ, has filed a petition against BP Products asserting certain air emissions and reporting violations at the Texas City refinery from 2005 to 2010, including in relation to the March 2005 explosion and fire. The Company is contesting the petition in a pending civil proceeding. In March 2010, TCEQ notified the DoJ of its belief that certain of the alleged violations may violate the October 25, 2007 plea agreement.

On August 9, 2010, the Texas Attorney General filed a separate petition against BP Products asserting emissions violations relating to an April 6, 2010 compressor fire and subsequent flaring event at the Texas City refinery's ultracracker unit. This emissions event is also the subject of a number of civil suits by many area workers and residents alleging personal injury and property damages and seeking substantial damages.

In September 2009, BP Products filed a petition to clarify specific required actions and deadlines under the 2005 Agreement with OSHA. That agreement resolved citations issued in connection with the March 2005 Texas City refinery explosion. OSHA denied BP Products' petition.

In October 2009 OSHA issued citations to the Texas City refinery seeking a total of $87.4 million in civil penalties for alleged violations of the 2005 Agreement and alleged process safety management violations. BP Products contested these citations. These matters were subsequently transferred for review to the Occupational Safety and Health (OSH) Review Commission.

A settlement agreement between BP Products and OSHA in August 2010 (2010 Agreement) resolved the petition filed by BP Products in September 2009 and the alleged violations of the 2005 Agreement. BP Products has paid a penalty of $50.6 million in that matter and agreed to perform certain abatement actions. Compliance with the 2010 Agreement (which is set to expire on March 12, 2012) is also a condition of probation due to the linkage between this 2010 Agreement and the 2005 Agreement.

On May 6, 2010, certain persons qualifying under the US Crime Victims Rights Act as victims in relation to the Texas City plea agreement requested that the federal court revoke BP Products' probation based on alleged violations of the Court's conditions of probation. The alleged violations of probation relate to the alleged failure to comply with the 2005 Agreement.

The OSHA process safety management citations issued in October 2009 were not resolved by the August 2010 settlement agreement. The proposed penalties in that matter are $30.7 million. The matter is currently before the OSH Review Commission which has assigned an Administrative Law Judge for purposes of mediation. These citations do not allege violations of the 2005 Agreement.

A shareholder derivative action was filed against several current and former BP officers and directors based on alleged violations of the CAA and OSHA regulations at the Texas City refinery subsequent to the March 2005 explosion and fire. An investigation by a special committee of BP's board into the shareholder allegations has been completed and the committee has recommended that the allegations do not warrant action by BP against the officers and directors. BP has filed a motion to dismiss the shareholder derivative action.

On November 29, 2007, BP Exploration (Alaska) Inc. (BPXA) entered into a criminal plea agreement with the DoJ relating to leaks of crude oil in March and August 2006. BPXA's guilty plea, to a misdemeanor violation of the US Water Pollution Control Act, included a term of three years' probation. On November 29, 2009 a spill of approximately 360 barrels of crude oil and produced water was discovered beneath a line running from a well pad to the Lisburne Processing Center in Prudhoe Bay, Alaska. On November 17, 2010, the US Probation Officer filed a petition in federal district court to revoke BPXA's probation based on an allegation that the Lisburne event was a criminal violation of state or federal law. A hearing is scheduled for the week of September 5, 2011. On May 12, 2008, a BP p.l.c. shareholder filed a consolidated complaint alleging violations of federal securities law on behalf of a putative class of BP p.l.c. shareholders against BP p.l.c., BPXA, BP America, and four officers of the companies, based on alleged misrepresentations concerning the integrity of the Prudhoe Bay pipeline before its shutdown on August 6, 2006. On February 8, 2010, the Ninth Circuit Court of Appeals accepted BP's appeal from a decision of the lower court granting in part and denying in part BP's motion to dismiss the lawsuit. Briefing is complete and oral argument was held on March 7, 2011. The Company awaits the court's decision.

On March 31, 2009, the DoJ filed a complaint against BPXA seeking civil penalties and injunctive relief relating to the 2006 oil releases. The complaint alleges that BPXA violated various federal environmental and pipeline safety statutes and associated regulations in connection with the two releases and its maintenance and operation of North Slope pipelines. The State of Alaska also filed a complaint on March 31, 2009 against BPXA seeking civil penalties and damages relating to these events. The complaint alleges that the two releases and BPXA's corrosion management practices violated various statutory, contractual and common law duties to the State, resulting in penalty liability, damages for lost royalties and taxes, and liability for punitive damages.

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. The Company owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of the Company and briefly indirectly owned a further 20% interest in Alyeska following the Company's combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, the Company will defend the claims vigorously.

On March 8, 2010, OSHA issued citations to the Company's Toledo refinery alleging violations of the Process Safety Management Standard, with penalties of approximately $3 million. These citations resulted from an inspection conducted pursuant to OSHA's Petroleum Refinery Process Safety Management National Emphasis Program. BP Products has contested the citations, and the matter is currently before the OSH Review Commission which has assigned an Administrative Law Judge to decide this proceeding.

The Company is the operator and 56% interest owner of the Atlantis unit in production in the Gulf of Mexico. In April 2009, Kenneth Abbott, as relator, filed a US False Claims Act lawsuit against the Company, alleging that the Company violated federal regulations, and made false statements in connection with its compliance with those regulations, by failing to have necessary documentation for the Atlantis subsea and other systems. That complaint was unsealed in May 2010 and served on the Company in June 2010. In September 2010, Kenneth Abbott and Food & Water Watch filed an amended complaint in the False Claims Act lawsuit seeking an injunction shutting down the Atlantis platform. The court denied the Company's motion to dismiss the complaint in March 2011. Separately, also in March 2011, BOEMRE issued its investigation report of the Abbott Atlantis allegations, which concluded that Mr. Abbott's allegations that Atlantis operations personnel lacked access to critical, engineer-approved drawings were without merit and that his allegations about false submissions by the Company to BOEMRE were unfounded.

BP Products' US refineries are subject to a 2001 consent decree with the EPA that resolved alleged violations of the CAA, and implementation of the decree's requirements continues. A 2009 amendment to the decree resolves remaining alleged air violations at the Texas City refinery through the payment of a $12 million civil fine, a $6 million supplemental environmental project and enhanced CAA compliance measures estimated to cost approximately $150 million. The fine has been paid, and BP Products is implementing the other provisions.

On September 30, 2010, the EPA and BP Products lodged a civil consent decree with the federal court in Houston. Following a public comment period, the federal court approved the settlement on December 30, 2010. The decree resolves allegations of civil violations of the risk management planning regulations promulgated under the CAA that are alleged to have occurred in 2004 and 2005 at the Texas City refinery. The agreement requires that BP Products pays a $15 -million civil penalty and that the Texas City refinery enhance reporting to the EPA regarding employee training, equipment inspection and incident investigation.

Various environmental groups and the EPA have challenged certain aspects of the operating permit issued by the Indiana Department of Environmental Management (IDEM) for upgrades to the Whiting refinery. In response to these challenges, the IDEM has reviewed the permits and responded formally to the EPA. The EPA, either through the IDEM or directly, can cause the permit to be modified, reissued, terminated or revoked. The Company is in discussions with the EPA and the IDEM over these and other CAA issues relating to the Whiting refinery. The Company is also in settlement negotiations with EPA to resolve alleged CAA violations at the Whiting, Toledo, Carson and Cherry Point refineries.

On February 9, 2011, Apache Canada Ltd commenced arbitration against BP Canada Energy. Apache alleges that in the future various of the sites that it acquired from BP Canada Energy pursuant to the parties' July 2010 Purchase and Sale Agreement will have to have work carried out to bring the sites into compliance with applicable Alberta environmental laws, and Apache Canada Ltd claims that the purchase price should be adjusted for its estimated possible costs. BP Canada Energy denies such costs will arise or require any adjustment to the purchase price. The process of selecting the arbitrator has begun. No hearing dates have been set.

Note 11 Short-Term Obligations

The Company's short-term obligations at December 31, 2010 and December 31, 2009 were $4,555 million and $4,565 million, respectively.

Included in this balance were US Industrial Revenue/Municipal Bonds where bondholders have the option to tender the bonds for repayment at interest reset dates, and the next reset date falls within 12 months of the balance sheet date. The amounts at the end of 2010 totaled $379 million, down from $2,914 million at the end of 2009.

Also included at December 31, 2009, was an amount of $1,622 million for loans associated with long-term gas supply contracts backed by gas prepaid bonds with tender options at interest rate reset dates, the Company functions as the liquidity provider for these bonds. Following the Gulf of Mexico oil spill the bonds failed re-marketing requiring the Company to acquire and hold all of the bonds, with a corresponding reduction to zero in the amount of loans reflected as outstanding at December 31, 2010.

Also included in the 2010 balance was $4,072 million (2009 zero) in respect of cash deposits received for asset disposals expected to be completed in 2011 which will be considered extinguished upon completion of the transactions.

At December 31, 2010, the Company, through its subsidiary, had substantial amounts of undrawn borrowing facilities available through committed BP facilities of $12,500 million (2009 $4,950 million), consisting of $5,250 million of standby facilities (of which $400 million is available to draw and repay by mid-September 2011, and $4,550 million until mid-October 2011, and $300 million until mid-January 2013) and $7,250 million of 364-day facilities (of which $4,000 million can be drawn until late May 2011 and is repayable up to 364 days from the date of drawing, $750 million until early July 2011, and $500 million until late August 2011). These facilities are with a number of international banks and the respective borrowings would be at pre-agreed rates. See Note 26.

Note 12 Accounts Payable

At December 31, 2010 and 2009, accounts payable included liabilities in the amounts of $231 million and $243 million, respectively, for checks issued in excess of related bank balances but not yet presented for collection.

Note 13 Long-Term Debt

The Company's non-affiliate long-term debt resides principally with three subsidiaries, BP Company North America Inc., BP Canada Energy Company and The Standard Oil Company.

Total long-term non-affiliate debt, excluding capital leases, at December 31, 2010 was $5,007 million. This amount excludes that portion of long-term debt, totaling $485 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing in each of the four years after December 31, 2011, in millions of dollars are: 2012-$1,091, 2013 - $87, 2014 - $99 and 2015 - $963.

The Company's long-term debt outstanding at December 31, 2010 and 2009 was as follows:

Millions of Dollars - December 31	2010	2009
<u>Non-Affiliate</u>		
Borrowings by BP Company North America Inc. and subsidiaries		
LIBOR plus 0.20% term loans due 2012 through 2021	$ 1,242	$ 1,223
LIBOR plus 2.50% to 3.50% term loan facility due 2015	962	-
LIBOR plus 0.50% Revolving Credit Facility due 2012	553	487
2.30% to 2.80% Notes due 2017 through 2044	446	386
9.13% Notes due 2011	254	258
8.50% Notes due 2012	177	177
8.25% to 8.63% Series B Notes due 2011 through 2022	161	163
8.75% to 9.13% Notes due 2031 through 2032	102	102
8.25% to 9.00% Notes due 2021 through 2022	84	84
5.00% to 7.38% Bonds due 2020 through 2021	60	61
Other	84	86
Borrowings by BP Canada Energy Company		
6.05% Debentures due 2030	126	113
Borrowings by The Standard Oil Company and subsidiaries		
5.85% Notes due 2019	928	928
Other	607	423
	5,786	4,491
Less current maturities	485	43
	$ 5,301	$ 4,448

Substantially all of the Company's non-affiliate debt, including the short-term obligations (not including asset sale deposits received) described in Note 11, has been guaranteed by BP.

At December 31, 2010, the Company had a long-term revolving credit facility with Repsol Netherlands Finance BV in the amount of $1,350 million. Borrowings under the facility at December 31, 2010 were $553 million.

At December 31, 2010, $126 million (2009 zero) of long-term debt was secured by the pledging of assets. In addition, in connection with $962 million (2009 zero) of long-term debt, the Company entered into crude oil sales contracts in respect of oil produced from certain fields in offshore Angola to provide security for the lending banks. The remainder of the long-term debt was unsecured.

In 2010, certain loans with non-affiliated lenders were repaid prior to their stated maturities.

Total long-term affiliate debt at December 31, 2010 was $33,850 million. No portion of this debt matures within one year. Annual maturities of affiliate long-term debt in each of the four years following 2011 in millions of dollars are: 2012 - $27,965, 2013 - $1,100, 2014 - $2,115 and 2015 - $2,000.

Millions of Dollars - December 31	2010	2009
Affiliate		
0.65% to 5.34% BP Asia Pacific Holdings Ltd loans due through 2013	$ 1,571	$ -
0.65% to 7.84% BP Asia Pacific Holdings Ltd loans due through 2013, 2017 and 2018	-	6,145
0.90% to 0.98% BP Asia Pacific Holdings Ltd variable rate loans due 2014 through 2016	265	-
3.68% to 4.85% BP Capital VOF loans due 2012 through 2015	20,000	-
LIBOR plus 1.8% to 2.25% BP Capital VOF loan due 2012	10,000	
3.83% to 4.85% BP International Limited loan due 2012 through 2015	-	20,000
1.75% to 5.55% BP International Limited variable rate loans due 2012 through 2013	-	1,360
2.99% to 5.81% BP International Limited fixed rate loans due 2012 through 2017	2,014	-
1.75% BP p.l.c. variable rate loan due 2010	-	1,110
	33,850	28,615
Less current maturities	-	1,410
	$ 33,850	$ 27,205

At December 31, 2010, the Company had one revolving credit facility with an affiliate (BP Capital V.O.F.) totaling $15,000 million, maturing in December 2012 and bearing interest at LIBOR plus an applicable margin ranging from 1.8% to 2.25%. At December 31, 2010, the Company had drawn $10,000 million. The facility does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The facility agreement contains a cross acceleration provision relating to the failure to pay principal or interest on other long-term debt obligations (that is, exceeding one year) representing more than $500 million.

During 2010, the Company entered into fixed rate loan agreements with an affiliate totaling $20,000 million. Amounts borrowed bear interest from 3.68% to 4.85%, and are repayable 2012 through 2015. This loan replaced a 2009 borrowing, also totaling $20,000 million from a different affiliate of the Company. The terms are included in the table above.

Note 14 Accruals and Reserves

The Company's non-current accrued liabilities, in total, are summarized in the table below.

Millions of Dollars - December 31	2010	2009
Accrued dismantlement, restoration and reclamation costs	$ 3,800	$ 3,123
Spill response	61	-
Other environmental accruals	1,498	1,418
Clean Water Act penalties	3,510	-
Litigation and claims	4,746	434
Employee benefit accruals	4,524	4,720
Deferred compensation	269	332
Derivative accruals	1,822	1,712
Obligations to equity accounted entities	1,905	2,419
Other non-current liabilities	3,326	1,986
	$ 25,461	$ 16,144

Accrued Liabilities relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described in Note 2. Accruals relating to the Gulf of Mexico spill, included in the table above (non-current portion only) are presented separately below.

Millions of Dollars	**Environ-mental**	**Spill response**	**Clean Water Act penalties**	**Litigation and claims**	**Total**
Balance at January 1, 2010	$ -	$ -	$ -	$ -	$ -
New obligations and changes in estimates of existing obligations	511	10,883	3,510	14,939	29,843
Spending on existing obligations	(129)	(9,840)	-	(3,966)	(13,935)
Balance at December 31, 2010	$ 382	$ 1,043	$ 3,510	$ 10,973	$ 15,908
Of which - Current (Accrued liabilities)	264	982	-	6,642	7,888
- Non-current (Accruals and reserves)	118	61	3,510	4,331	8,020
- Payable from the trust fund	382	-	-	9,152	9,534

As described in Note 2, the Company recorded liabilities, at December 31, 2010, relating to the Gulf of Mexico oil spill including amounts in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties, each of which is described below.

Environmental

As a responsible party under the OPA 90, the Company faces claims by the United States, as well as by state, tribal, and foreign trustees, if any, for natural resource damages (Natural Resource Damages claims). These damages include, among other things, the reasonable costs of assessing the injury to natural resources as well as some emergency restoration projects which are expected to occur over the next two years. The Company has been incurring natural resource damage assessment costs and a reserve has been made for the estimated costs of the assessment phase. The assessment covers a large area of potential impact and will take some time to complete in order to determine both the severity and duration of the impact of the oil spill. The process of interpreting the large volume of data collected is expected to take at least several months and, in order to determine potential injuries to certain animal populations, data will need to be collected over one or more reproductive cycles. This expected assessment spend is based upon past experience as well as identified projects. A liability of $382 million has been established for these items. Until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims, therefore no amounts have been provided for these items and they are disclosed as a contingent liability. See Note 10 for further information.

Spill response

The remaining liability for spill response includes the estimated future costs of both subsea operations as well as surface and shoreline work. The subsea response reserve is based on the remaining activities expected to be undertaken and has been calculated using daily rates of costs incurred to date. This includes the rig costs to complete the plugging and abandonment of the second relief well, which was completed on March 8, 2011, and the recovery of the subsea infrastructure used as part of the various containment systems. The majority of the vessels involved in the response have now been decontaminated. The liability accrued includes the costs of decontaminating the remaining 25 vessels, which is expected to be completed by the end of June 2011. The liability recorded for surface and shoreline response is based on the daily costs currently being incurred which are underpinned by headcount, equipment and the number of vessels on hire. At the end of the year, there were approximately 360 vessels on hire and the number of personnel involved in response activities was approximately 6,200. The Company and the US Coast Guard are working closely with state and local officials to clean Gulf Coast beaches before the 2011 spring and summer tourism seasons and this is the basis on which the liability at December 31, 2010 has been calculated. The liability also includes an estimate of future federal response costs and ongoing monitoring that will be required until the end of the second quarter of 2012.

Litigation and claims

Individual and Business Claims, and State and Local Claims under the OPA 90 and claims for personal injury

The Company faces claims under the OPA 90 by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity, loss of subsistence use of natural resources and for personal injury (Individual and Business Claims) and by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs (State and Local Claims).

The estimated future cost of settling Individual and Business Claims, State and Local Claims under the OPA 90 and claims for personal injuries, both reported and unreported, has been provided for. Claims administration costs have also been provided for. The Company believes that the history of claims received to date, and settlements made, provides sufficient data to enable the Company to use an approach based on a combination of actuarial methods and management judgments to estimate IBNR (Incurred But Not Reported) claims to determine a reliable best estimate of the Company's exposure for claims not yet reported in relation to Individual and Business claims, and State and Local claims under the OPA 90. The amount provided for these claims has been determined in accordance with US GAAP and represents the Company's current best estimate of the expenditure required to settle its obligations at the balance sheet date. The measurement of this accrued liability is subject to significant uncertainty. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses.

In estimating the amount of the liability, the Company has determined a range of possible outcomes for Individual and Business Claims, and State and Local Claims. These determinations are based on the Company's claims payment experience, the application of insurance industry benchmark data, the use of a combination of actuarial and statistical methods and management judgments where appropriate. The methods selected are consistent with those used by the insurance industry to estimate a range of total expenditures for both reported and unreported claims. These methods have been adopted on the basis that, at this stage of development, the application of insurance industry standard techniques for the estimation of ultimate losses is an appropriate approach for the costs arising from the Deepwater Horizon oil spill.

Through the application of this approach, the Company concluded that a reasonable range of possible outcomes for the amount provided, at December 31, 2010, was $6 billion to $13 billion. The Company believes that the liability recorded at December 31, 2010 of $9,152 million represents the best estimate within the range of possible outcomes. This amount is shown as payable from the trust fund under Litigation and claims in the table above. The liability is in addition to the $3,362 million of claims paid in 2010. Of this total paid, $3,178 million is included within spend of the accrued liability in the table, and the remaining $184 million was a period expenditure prior to the recognition of the accrued liability at the end of the second quarter 2010. Also included within the total Litigation and claims of $3,966 million are amounts relating to claims administration costs and legal fees. Of the total payments of $3,362 million during the year, $2,963 million was paid out of the trust fund and $399 million was paid by the Company.

The Company's management utilized actuarial techniques and its judgment in determining this reliable best estimate. However, it is possible that the final outcome could lie outside this range. Many key assumptions underlie and influence both the range of possible outcomes and the reliable best estimates of total expenditures derived for both categories of claims. These key assumptions include the amounts that will ultimately be paid in relation to current claims, the number, type and amounts for claims not yet reported, the scope and number of claims that can be resolved successfully in the claims process, the resolution of rejected claims, the outcomes of any litigation, the effects on tourism and fisheries and other economic and environmental factors. The outcomes of claims and litigation are likely to be paid out over many years to come. The Company will re-evaluate the assumptions underlying this analysis on a quarterly basis as more information becomes available and the claims process matures. The Company also faces other litigation for which no reliable estimate of the cost can currently be made. Therefore no amounts have been provided for these items. See Note 10 for further information.

Legal fees

Estimated legal fees have been provided for where the Company has been able to estimate reliably those which will arise in the next two years.

Clean Water Act penalties

A liability was been recorded for the estimated penalties for strict liability under Section 311 of the Clean Water Act. Such penalties are subject to a statutory maximum calculated as the product of a per-barrel maximum penalty rate and the number of barrels of oil spilled. Uncertainties currently exist in relation to both the per-barrel penalty rate that will ultimately be imposed and the volume of oil spilled. A charge for potential Clean Water Act Section 311 penalties was first recorded by the Company in June 2010. At the time that charge was taken, the latest estimate from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response was between 35,000 and 60,000 barrels per day. The mid-point of that range, 47,500 barrels per day, was used for the purposes of calculating the charge. For the purposes of calculating the amount of the oil flow that was discharged into the Gulf of Mexico, the amount of oil that had been or was projected to be captured in vessels on the surface was subtracted from the total estimated flow up until when the well was capped on July 15, 2010. The result of this calculation was an estimate that approximately 3.2 million barrels of oil had been discharged into the Gulf. This estimate of 3.2 million barrels was calculated using a total flow of 47,500 barrels per day multiplied by the 85 days from April 22, 2010 through July 15, 2010 less an estimate of the amount captured on the surface (approximately 850,000 barrels).

This estimated discharge volume was then multiplied by $1,100 per barrel – the maximum amount the statute allows in the absence of gross negligence or willful misconduct – for the purposes of estimating a potential penalty. This resulted in $3,510 million being provided for by the Company for potential penalties under Section 311 of the Clean Water Act.

In utilizing the $1,100 per-barrel input, the Company took into account that the actual per-barrel penalty a court may impose, or that the US government might agree to in settlement, could be lower than $1,100 per barrel if it were determined that such a lower penalty was appropriate based on the factors a court is directed to consider in assessing a penalty. In particular, in determining the amount of a civil penalty, Section 311 of the Clean Water Act directs a court to consider a number of enumerated factors, including, "the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require." Civil penalties above $1,100 per barrel up to a statutory maximum of $4,300 per barrel of oil discharged would only be imposed if gross negligence or willful misconduct were alleged and subsequently proven. The Company expects to seek assessment of a penalty lower than $1,100 per barrel based on several of these factors. However, the $1,100 per-barrel rate was utilized for the purposes of calculating a charge after considering and weighing all possible outcomes and in light of: (i) the Company's conclusion that it did not act with gross negligence or engage in willful misconduct; and (ii) the uncertainty as to whether a court would assess a penalty below the $1,100 statutory maximum.

On August 2, 2010, the United States Department of Energy and the Flow Rate Technical Group issued an estimate that 4.9 million barrels of oil had flowed from the Macondo well, and 4.05 million barrels had been discharged into the Gulf (the difference being the amount of oil captured by vessels on the surface as part of the Company's well containment efforts).

It was and remains the Company's view, based on the analysis of available data by its experts, that the August 2, 2010 US government estimate and other similar estimates are not reliable estimates because they are based on incomplete or inaccurate information, rest in large part on assumptions that have not been validated, and are subject to far greater uncertainties than have been acknowledged. As the Company has publicly asserted, including at an October 22, 2010 meeting with the staff of the National Commission, the Company believes that the August 2, 2010 discharge estimate and similar estimates are overstated by a significant amount, and that the flow rate is potentially in the range of 20-

50% lower. If the flow rate is 50% lower than the August 2, 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 2.5 million barrels, and the amount discharged into the Gulf would be approximately 1.6 million barrels. If the flow rate is 20% lower than the August 2, 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 3.9 million barrels and the amount discharged into the Gulf would be approximately 3.1 million barrels, which is not materially different from the amount used in the Company's original estimate at the second quarter.

Therefore, for the purposes of calculating a liability for fines and penalties under Section 311 of the Clean Water Act, the Company has continued to use an estimate of 3.2 million barrels of oil discharged to the Gulf of Mexico as its current best estimate of the amount which may be used in calculating the penalty under Section 311 of the Clean Water Act. This reflects an estimate of total flow from the well of approximately 4 million barrels, and an estimate of approximately 850,000 barrels captured by vessels on the surface. In utilizing this estimate, the Company has taken into consideration not only its own analysis of the flow and discharge issue, but also the analyses and conclusions of other parties, including the US government. The estimate of the Company and of other parties as to how much oil was discharged to the Gulf of Mexico may change, perhaps materially, over time. One factor that would impact the flow rate estimate is the completion of the analysis on the blowout preventer which is now in the custody of the federal government. Similar situations exist with regard to other pieces of physical evidence critical to the flow rate analysis. Changes in estimates as to flow and discharge could affect the amount actually assessed for Clean Water Act fines and penalties. The year-end accrual continued to be based on a per-barrel penalty of $1,100 for the reasons discussed above, including the Company' s continued conclusion that it did not act with gross negligence or engage in willful misconduct.

The amount and timing of these costs will depend upon what is ultimately determined to be the volume of oil spilled and the per-barrel penalty rate that is imposed. It is not currently practical to estimate the timing of expending these costs and the accrual has been included within non-current liabilities on the consolidated balance sheet. No other amounts have been provided as of December 31, 2010, in relation to other potential fines and penalties because it is not possible to measure the obligation reliably. Fines and penalties are not covered by the trust fund.

Note 15 Accrued Dismantlement, Restoration and Reclamation Costs

The following table presents changes in the Company's current (included in accrued liabilities) and non-current (included in accruals and reserves) accrued dismantlement, restoration and reclamation costs.

Millions of Dollars	**2010**	**2009**
Balance at January 1	$ 3,263	$ 3,118
Accretion of discount	174	189
New obligations and changes in estimates of existing obligations	1,230	(174)
Spending on existing obligations	-	(2)
Property dispositions	(611)	(16)
Foreign currency translation	-	148
Balance at December 31	$ 4,056	$ 3,263

The Company records a liability for the future cost of dismantlement, restoration and reclamation of oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The liability for these production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using a risk free, credit-adjusted interest rate. These costs are generally expected to be incurred over the next 30 years. While the liability is based on the assessment of expected future cash flows and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of these costs.

The level of increase in the liability varies, among other things, with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews. In Exploration and Production, there was a significant increase in 2010, driven by activity in the Gulf of Mexico. On October 15, 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued Notice to Lessees (NTL) 2010-G05, which requires that idle infrastructure on active leases to be retired earlier than previously was required. The regulation also establishes guidelines to determine the future utility of idle infrastructure on active leases. As a consequence, the timing and methodology of well abandonment have changed. This is reflected in an increase to the liability related to idle infrastructure during the year. The Company also undertakes periodic reviews of existing liabilities.

Note 16 Leases

The Company leases various types of properties, including rigs, service stations, tankers, buildings, railcars and other facilities, some of which are subleased to others. Some of the leases and subleases provide for contingent rentals based on refined product throughput.

Summarized below are the future minimum rental payments and related sublease rental income for non-cancelable operating leases as of December 31, 2010.

Millions of Dollars	Rental Payments	Rental Income
2011	$ 2,085	$ 80
2012	1,532	61
2013	1,209	46
2014	870	27
2015	625	16
Thereafter	1,645	44
Total future minimum rental payments	$ 7,966	$ 274

Rental expense and related rental income applicable to operating leases are summarized below.

Millions of Dollars – Year Ended December 31	2010	2009	2008
Minimum rental expense	$ 3,766	$ 2,467	$ 2,700
Less – related rental income	85	81	132
Net rental expense	$ 3,681	$ 2,386	$ 2,568

Note 17 Foreign Currency

Income for 2010, 2009 and 2008 includes foreign currency (losses) gains of ($521 million), ($123 million) and $477 million respectively. A foreign currency loss of $528 million in 2010 relates to repayment of an Australian dollar denominated loan. The foreign currency translation adjustment included in shareholder's equity for 2010, 2009 and 2008 reflects net translation gains (losses) of ($589 million), $389 million and ($1,225 million), respectively. As a result of the BPAGL deconsolidation, a cumulative translation net gain of $321 million was derecognized. See Note on Organization and Accounting Changes for further information.

Note 18 Interest Expense

The Company capitalizes interest cost related to the financing of major projects under development. All other interest is expensed as incurred.

Millions of Dollars - Year Ended December 31	2010	2009	2008
External financing and other	$ 472	$ 383	$ 519
Affiliates	1,309	902	993
	1,781	1,285	1,512
Less - capitalized interest	172	146	115
Net interest expense	$ 1,609	$ 1,139	$ 1,397

Affiliate interest expense primarily results from the Company's affiliate borrowings. In addition, certain accounts payable - affiliates balances are interest bearing.

Note 19 Research and Development Expenses

Research and development costs are expensed as incurred and amounted to $518 million in 2010, $307 million in 2009 and $283 million in 2008.

Note 20 Taxes

Millions of Dollars - Year Ended December 31	2010	2009	2008
Income tax expense (benefit)			
Federal:			
Current	$ 191	$ 281	$ 2,659
Deferred	(7,716)	(77)	936
Foreign:			
Current	3,300	2,315	4,728
Deferred	656	30	202
State and Local:			
Current	311	403	624
Deferred	(106)	102	(51)
	$ (3,364)	$ 3,054	$ 9,098

The provision for income taxes differs from the amount computed by applying the statutory income tax rate as follows:

Millions of Dollars - Year Ended December 31	2010	2009	2008
Pre-tax (loss) income:			
US source	$ (24,630)	$ (496)	$ 11,145
Foreign source	9,877	7,461	11,977
	$ (14,753)	$ 6,965	$ 23,122
Income tax (benefit) provision at US statutory rates	(5,164)	2,438	8,093
Foreign taxes, net of Federal income tax benefit	525	(356)	949
State income taxes, net of Federal income tax benefit	133	328	372
Tax credits	(54)	(83)	(77)
Prior period adjustments	(147)	(37)	(147)
Fines and penalties	1,247		
Goodwill allocated to disposals and impairment	(40)	637	-
Manufacturing deduction	-	-	(116)
Other	136	127	24
	$ (3,364)	$ 3,054	$ 9,098

Millions of Dollars - Year Ended December 31	2010	2009	2008
Taxes other than income taxes			
Excise	$ 11,504	$ 10,760	$ 10,792
Production and severance	1,485	946	3,197
Real estate, personal property and other	569	383	415
	$ 13,558	$ 12,089	$ 14,404

At December 31, 2010 and 2009, the major components of deferred tax assets and liabilities were as follows.

Millions of Dollars - December 31	2010	2009
Deferred tax liabilities		
Accelerated depreciation, depletion and amortization	19,013	$ 17,129
Other	752	734
	19,765	17,863
Deferred tax assets		
Tax credit carryforwards	4,002	3,010
Postretirement benefits	1,744	1,967
Other employee benefits	871	1,017
Environmental and restoration costs	6,763	1,702
Other	2,755	507
Gross deferred tax assets	16,135	8,203
Deferred tax asset valuation allowance (1)	(1,900)	(2,018)
	14,235	6,185
Net deferred tax liability	$ 5,530	$ 11,678

(1) The $118 million change in the valuation allowance resulted from expiring credits and adjustments resulting from the audit of prior year carryforwards.

Deferred income tax (assets) and liabilities are included in the consolidated balance sheet as shown below. Deferred income tax (assets) and liabilities are classified as current and non-current consistent with the classification of the related temporary differences and separated by tax jurisdiction.

Millions of Dollars – December 31	2010	2009
Prepaid expenses and other	$ (3,603)	$ (1,000)
Non-current deferred income taxes	9,133	12,678
	$ 5,530	$ 11,678

Undistributed earnings of certain foreign subsidiaries and joint venture companies amounted to $3,753 million at December 31, 2010, which, under existing law, will not be subject to US tax until distributed as dividends. While the timing of the repatriation will depend on business needs, there are no immediate plans for significant repatriation of these funds. Any taxes paid to foreign governments on those earnings may be used in whole or in part as credits against the US tax on any dividends distributed from such earnings. It is not anticipated that any incremental US tax will result upon distribution, above amounts already provided.

The Company has $3,546 million of foreign tax credit carryforwards for US income tax purposes. A valuation allowance of $1,900 million has been recorded against these credits. If unused, these credits are scheduled to expire in 2011 through 2019. Tax credit carryforwards also include alternative minimum tax credits of $406 million. Alternative minimum tax credits may be carried forward indefinitely; the Company expects full utilization of these credits.

The Company files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the Company's income tax returns, principally for the years 2006 through 2010. Tax returns for these years contain matters that could be subject to differing interpretations of applicable tax laws and regulations as they relate to the amount, timing or inclusion of revenues and expenses or the sustainability of income tax credits for a given audit cycle. The resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. The Company completed the IRS audit settlement cycle for the audit years 2004-2005 in 2010. There were no significant impacts on the consolidated statement of operations as a result of the settlements. At the present time, the Company does not have any significant issues that are expected to settle in the next 12 months.

The following table summarizes the significant open tax years that remain subject to examination for each of the Company's major tax jurisdictions.

Tax Jurisdiction	**Open Tax Years**
United States	2006 to 2010
Trinidad	2001 to 2010
Norway	2001 to 2010
Angola	2007 to 2010

The Company includes interest and penalties related to unrecognized tax benefits in income tax expense in the consolidated statement of operations. During the years ended December 31, 2010, 2009 and 2008 the net interest and penalty expense recognized by the Company amounted to $90 million, $380 million and $10 million, respectively. The net payable for interest and penalties, which is included in accruals and reserves in the consolidated balance sheet, amounted to approximately $393 million and $309 million at December 31, 2010 and 2009, respectively.

Note 21 Pension and Other Postretirement Benefits

The Company and its subsidiaries have a number of defined benefit pension plans covering most employees. Plan benefits are generally based on length of service and level of compensation. Substantially all of the costs associated with the plans are the responsibility of the Company and its subsidiaries. Contributions to the funded pension plans are made in sufficient amounts to meet the minimum funding requirements of the applicable laws and regulations. Additional funding may be made as deemed appropriate.

In addition, the Company and its subsidiaries provide certain health care and life insurance benefits for retired employees and their dependents. Costs charged to the Company for retirees are based on age and length of service at retirement. Health care benefits are provided through insured and self-insured plan arrangements. These plans are not generally pre-funded.

For certain operations located outside of the United States, pension and health care benefits are provided by plans sponsored by subsidiaries of the Company.

The following table summarizes the benefit obligations, funded status and balance sheet components associated with the principal pension and other postretirement benefit plans based upon the actuarial valuations prepared as of December 31, 2010 and 2009.

Millions of Dollars	Pension Benefits 2010	Pension Benefits 2009	Postretirement Benefits 2010	Postretirement Benefits 2009
Change in benefit obligation				
Obligation at beginning of year	$ 8,758	$ 8,535	$ 3,060	$ 3,052
Service cost	291	275	49	50
Interest cost	468	499	173	187
Participant contributions	7	4	-	-
Plan amendments	-	-	-	(22)
Settlement loss	20	304	-	-
Curtailment gain	(19)	-	(1)	-
Special termination benefit	8	-	1	-
Benefits paid	(331)	(341)	(199)	(196)
Settlements paid	(587)	(1,192)	-	8
Currency exchange rate changes	71	196	3	-
Divestments(1)	(396)	-	-	-
Actuarial loss (gain)	723	478	148	(19)
Obligation at end of year	$ 9,013	$ 8,758	$ 3,234	$ 3,060
Change in plan assets				
Fair value at beginning of year	$ 6,847	$ 6,132	$ 12	$ 13
Actual return on plan assets	947	1,145	-	3
Participant contributions	7	4	-	-
Employer contributions	797	867	-	-
Benefits paid	(308)	(315)	(4)	(4)
Settlements paid	(533)	(1,141)	-	-
Divestments(1)	(377)	-	-	-
Currency exchange rate changes	64	155	-	-
Fair value at end of year	$ 7,444	$ 6,847	$ 8	$ 12

(1) Divestments included above relate to Australian entities that are no longer consolidated by BP America Inc.

Millions of Dollars	Pension Benefits 2010	Pension Benefits 2009	Postretirement Benefits 2010	Postretirement Benefits 2009
Funded status				
Unfunded	$ (1,569)	$ (1,911)	$ (3,226)	$ (3,048)
Net amount recognized	$ (1,569)	$ (1,911)	$ (3,226)	$ (3,048)
Balance sheet components				
Current liabilities	$ (64)	$ (41)	$ (207)	$ (198)
Other non-current liabilities	(1,505)	(1,870)	(3,019)	(2,850)
Net amount recognized	$ (1,569)	$ (1,911)	$ (3,226)	$ (3,048)

Employer contributions and benefit payments for unfunded plans are not included in the change in plan assets. Such benefits are paid out of general corporate assets.

The accumulated benefit obligations for all pension plans were $8,571 million and $8,306 million at December 31, 2010 and 2009, respectively.

The accumulated benefit obligation and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were $8,320 million and $7,164 million, respectively, as of December 31, 2010 and were $8,063 million and $6,585 million, respectively, as of December 31, 2009.

The projected benefit obligation and fair value of plan assets for pension plans with projected benefit obligations in excess of plan assets were $9,013 million and $7,444 million, respectively, as of December 31, 2010 and were $8,758 million and $6,847 million, respectively, as of December 31, 2009.

Components of the net periodic benefit cost recognized in the consolidated statement of operations are as follows for the years ended December 31, 2010, 2009 and 2008.

	Pension Benefits			Postretirement Benefits		
Millions of Dollars	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Service cost	$ 291	$ 275	$ 278	$ 49	$ 50	$ 42
Interest cost	468	499	512	173	187	201
Expected return on plan assets	(627)	(608)	(678)	(1)	(1)	(2)
Settlements, curtailments and other	42	661	11	1	-	-
Amortization of prior service cost	24	26	24	(54)	(52)	(54)
Amortization of unrecognized net loss	214	210	180	2	4	28
Net periodic benefit cost	$ 412	$ 1,063	$ 327	$ 170	$ 188	$ 215

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

The following table summarizes the pre-tax amounts included in accumulated other comprehensive income at December 31, 2010.

Millions of Dollars	Pension Benefits	Post retirement Benefits
Prior service costs	$ 114	$ (240)
Actuarial net loss	4,294	174
	$ 4,408	$ (66)

Pre-tax amounts included in accumulated other comprehensive income at December 31, 2010 that are expected to be recognized as components of net periodic postretirement benefit cost during 2011 are as follows:

Millions of Dollars	Pension Benefits	Post retirement Benefits
Prior service costs	$ 23	$ (53)
Actuarial net loss	290	16
	$ 313	$ (37)

Assumptions

The following weighted-average assumptions were used to determine benefit obligations and net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008.

	Pension Benefits			Postretirement Benefits		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Weighted-average assumptions as of December 31						
Used to determine benefit obligations						
Discount rate	4.7%	5.4%	6.3%	5.3%	5.8%	6.2%
Compensation increase	4.1	4.2	2.2	-	-	-
Used to determine net periodic benefit cost						
Discount rate	5.4%	6.3%	6.1%	5.8%	6.2%	6.4%
Expected return on assets	8.0	8.0	8.0	7.6	7.3	7.6
Compensation increase	4.2	2.2	4.2	-	-	-

The expected rate of return on plan assets reflects the Company's expectations built up by asset class and by plan. The Company's expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. The assumption for return on equities is based on a long-term view; the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. The assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

The Company reviews external data and its own historical trends for health care costs to determine the healthcare cost trend rates for the other postretirement benefit plans. For the measurement of accumulated postretirement benefit obligation at December 31, 2010, for the principal US postretirement medical plan, the assumed health care cost trend rate starts with 7.8 percent in 2011 and gradually declines to 5 percent for 2018 and beyond. For this measurement at December 31, 2009, the assumed health care cost trend rate started with 8 percent and gradually declined to 5 percent for 2016 and beyond.

Sensitivity

Assumed health care cost trend rates have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in the assumed health care cost trend rates would have had the following effects on the projected benefit obligations as of December 31, 2010 and on cost for 2010.

Millions of Dollars	One percentage point Increase	One percentage point Decrease
Effect on total service and interest cost for 2010	$ 28	$ (21)
Effect on year end 2010 postretirement benefit obligation	359	(300)

Plan Assets

A significant portion of the assets of the Company's pension plans are managed in a master trust. The overall investment strategy of the assets within the master trust is to achieve a well diversified portfolio that balances risk and return with the primary objective to provide a pool of assets sufficient to meet the obligations to plan participants. The Company invests the assets of the plans in a manner consistent with its fiduciary obligations and principles that reflect current practices in portfolio management. The risk management practices associated with the investment program include establishing an overall risk budget, reviews of relative tracking error of the various strategies to their associated benchmarks, overall volatility metrics, liquidity considerations, total and active investment management risk and various compliance-related monitoring and verification measures.

The investment program seeks to achieve a rate of return that meets or exceeds the actuarial calculated discounted rate of return as determined for any given year. The allocations to the various asset classes (as shown in the table below) are determined by the results of an asset liability analysis conducted in conjunction with an external investment consultant. The asset liability analysis considers many factors including individual and overall asset class diversification, actual and forecasted asset class returns, market scenarios and the liabilities associated with the plans.

The Company uses exchange-traded and over-the-counter derivative financial instruments for the purpose of asset allocation, as a substitute for physical investing and management of foreign currency, interest rate and other market risks. Derivative financial instruments include futures contracts (used to achieve a desired asset allocation and as a substitute for physical investing), options (used to enhance investment returns and manage market risk), currency forwards (used to manage foreign currency risk) and interest rate swaps (used to manage interest rate risk).

Direct investment of plan assets in either securities or real property of the Company or any affiliate is generally prohibited.

In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolio is diversified by asset class exposure. The diversification of the portfolio reduces any significant concentration of risk. The investment policy ranges for the major asset classes are as follows:

Asset Class	Target Allocation	Allocation Range
Equity securities:		
US equity securities	40%	25 – 55%
Non-US equity securities	20	10 – 30
Fixed income securities	19	15 – 30
Private equity investments	15	7 – 23
Other private equity funds	5	0 – 10
Cash equivalents	1	0 – 10

Fair Value Measurements of Plan Assets

For a discussion of the methods employed by the Company to measure the fair value of invested assets, see Note 7. The following discussion of fair value measurements applies exclusively to the Company's pension and other postretirement benefit plan assets.

The following tables present the level within the fair value hierarchy at which the financial assets of the Company's principal pension plans are measured on a recurring basis at December 31, 2010 and 2009.

Millions of Dollars	Prices in Active Markets for Identical Assets (Level 1)	Observable (Level 2)	Unobservable (Level 3)	Total
December 31, 2010				
Asset class				
Cash equivalents:				
US treasury bills, short-term funds and daily repurchase agreements (a)	$ -	$ 566	$ -	$ 566
Equity securities:				
Common stocks (b)	842	-	-	842
Registered investment companies (b)	376	-	-	376
Commingled investment funds (c)	-	1,623	-	1,623
Non-US equity investment funds (c)	-	1,420	-	1,420
Fixed income securities:				
Government securities (d)	-	36	-	36
Corporate bonds (d)	-	27	-	27
Fixed income investment funds (c)	-	1,342	-	1,342
Private equity investments:				
Venture capital funds (e)	-	-	286	286
Buyout funds (e)	-	-	774	774
Other private equity funds (e)	-	-	173	173
Insurance company general accounts (f)	-	13	-	13
Total investments	$ 1,218	$ 5,027	$ 1,233	7,478
Cash				3
Receivables				2
Payables				(39)
Total				$ 7,444

Millions of Dollars	Prices in Active Markets for Identical Assets (Level 1)	Observable (Level 2)	Unobservable (Level 3)	Total
December 31, 2009				
Asset class				
Cash equivalents:				
US treasury bills, short-term funds and daily repurchase agreements (a)	$ -	$ 359	$ -	$ 359
Equity securities:				
Common stocks (b)	561	-	-	561
Registered investment companies (b)	314	-	-	314
Commingled investment funds (c)	-	1,449	-	1,449
Non-US equity investment funds (c)	-	1,831	-	1,831
Fixed income securities:				
Government securities (d)	-	36	-	36
Corporate bonds (d)	-	26	-	26
Fixed income investment funds (c)	-	1,236	-	1,236
Private equity investments:				
Venture capital funds (e)	-	-	240	240
Buyout funds (e)	-	-	635	635
Other private equity funds (e)	-	-	147	147
Insurance company general accounts (f)	-	13	-	13
Total investments	$ 875	$ 4,950	$ 1,022	6,847
Cash				64
Payables				(64)
Total				$ 6,847

(a) US treasury bills, short-term funds and daily repurchase agreements are valued at cost which approximates fair value.

(b) Common stocks and registered investment companies are valued at the quoted closing price reported on the active market on which the individual securities are traded.

(c) Investment funds are valued using the net asset value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities and then divided by the number of shares outstanding.

(d) Government securities and corporate bonds are valued using a combination of the quoted closing price reported on the active market on which the individual securities are traded and an evaluation of the expected yield relative to similar securities.

(e) Private equity investments and other private equity funds are valued based on the capital account statements provided by the general partner. The general partner uses various valuation techniques and inputs in valuing the private investments in the partnership, including purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples, discounted cash flow analysis, market conditions, liquidity, current operating results and other pertinent information.

(f) Insurance company general accounts are valued by the administrator of the fund based on the combination of cash flows into and out of the fund and the performance of the invested assets of the account. Interest is credited to the account using rates announced in advance. The rate is set by the administrator based on an estimate of the investment experience for the year. The account is invested primarily in investment grade publicly traded and privately placed debt securities and mortgage loans.

For the year ended December 31, 2010, there were no assets transferred into or out of Levels 1 and 2.

The changes in Level 3 assets for the years ended December 31, 2010 and 2009 are as follows:

Millions of Dollars	Venture capital funds	Buyout funds	Other private equity funds	Totals
Balance at January 1, 2009	$ 218	$ 665	$ 117	$1,000
Activity during 2009				
Actual return on plan assets:				
Related to assets sold during the year	4	12	4	20
Related to assets still held at year end	(21)	(66)	18	(69)
Purchases, sales, and settlements (net)	39	24	7	70
Transfers into Level 3	-	-	1	1
Balance at December 31, 2009	240	635	147	1,022
Activity during 2010				
Actual return on plan assets:				
Related to assets sold during the year	(7)	34	(4)	23
Related to assets still held at year end	-	72	26	98
Purchases, sales, and settlements (net)	53	33	4	90
Balance at December 31, 2010	$ 286	$ 774	$ 173	$1,233

Other Postretirement Benefit Plan Assets

The other postretirement benefit plan overall investment objective is to invest in a money market vehicle. Prior to July 1, 2010, the assets of the plan were invested in commingled investment funds having 70% equity and 30% fixed income allocation.

All of the Company's other postretirement benefit plan assets for December 31, 2010 and 2009 amounting to $8 million and $12 million, respectively, are classified Level 2 within the fair value hierarchy as they are commingled investment funds valued using the NAV provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities and then divided by the number of shares outstanding.

Cash Flows

Plan Contributions

During 2010, the Company made contributions of $797 million to its funded pension plans, which included discretionary contributions above the minimum funding required by applicable laws and regulations. The Company expects to make contributions in 2011 of approximately $714 million, which includes discretionary contributions.

Estimated Future Benefit Payments

The following table presents estimated future benefit payments for the next ten years:

Millions of Dollars - Year Ended December 31	Pension Benefits	Postretirement Benefits	Subsidy Receipts
2011	$ 855	$ 234	$ 22
2012	857	238	24
2013	863	244	25
2014	859	250	27
2015	839	255	28
Years 2016 through 2020	3,919	1,322	154

Defined Contribution Plans

Most employees are eligible to participate in defined contribution plans by contributing a portion of their compensation. The Company and its subsidiaries match contributions up to specified percentages of each employee's compensation. Matching contributions were $178 million in 2010, $182 million in 2009 and $181 million in 2008.

Note 22 Transactions with BP and Subsidiaries

The Company and its subsidiaries have transactions in the ordinary course of business with BP and with other members of the BP group. Such transactions include the sale of crude oil, petroleum products, chemicals and other goods and services amounting to $9,783 million in 2010, $8,061 million in 2009 and $13,248 million in 2008, and purchases of similar items amounting to $22,292 million in 2010, $16,827 million in 2009 and $28,246 million in 2008. In addition, the Company engaged in transactions with BP group companies resulting in other operating revenues of $249 million in 2010, $273 million in 2009 and $305 million in 2008.

BP group financing transactions resulted in interest income of $102 million and interest expense of $1,309 million in 2010, interest income of $150 million and interest expense of $902 million in 2009 and interest income of $422 million and interest expense of $993 million in 2008. The BP group has a centralized treasury function. As part of this function business cash requirements are funded and surplus cash is invested, on a pooled basis. Amounts received from, and amounts transferred to, the BP group are settled in the ordinary course of business and bear interest based on LIBOR adjusted for an applicable margin. These amounts are classified as receivables – affiliates and accounts payables – affiliates in the consolidated balance sheet. The interest bearing balances included in receivables – affiliates at December 31, 2010 and 2009 are $9,523 million and $7,215 million, respectively, and the interest bearing balances included in accounts payable – affiliates at December 31, 2010 and 2009 are $26 million and $133 million, respectively.

Amounts classified as non-current amounts due from affiliates and amounts due to affiliates, include loan facility agreements between subsidiaries within the BP group. Under these agreements amounts are made available to the borrower for a period of longer than one year. Settlement of these amounts is expected during 2012-2015. The Company also has long-term balances arising from activity outside of the centralized treasury function as a result of various transactions with affiliates. These balances are periodically reviewed for settlement.

The Company paid royalties amounting to $91 million in 2010, $130 million in 2009 and $54 million in 2008.

The Company did not pay dividends to its parent in 2010. In 2009 and 2008, the Company paid $10,000 million and $338 million, respectively.

Certain subsidiaries of the Company have equity shares, non-controlling interests, owned by affiliates of BP. Dividends paid on these non-controlling interests in 2010, 2009 and 2008 amounted to $388 million, $505 million and $744 million, respectively. No dividends were received from the BP group in 2008, 2009 and 2010.

In December 2010, the Company's ownership interest in a consolidated entity, BP Australia Group Pty, Ltd. (BPAGL), was converted to a preferred stock investment valued at $5.7 billion. Concurrently the Company's ownership in BPAGL was diluted from 75 percent to 49 percent. The reduction resulted from BPAGL issuing additional shares to a United Kingdom owned affiliate of the Company in exchange for a loan receivable. At December 31, 2010, BPAGL was no longer a consolidated entity of the Company.

The Company and BP International routinely provide certain administrative, financial, professional and other services for the benefit of the other party. Under the terms of a services agreement, the Company and BP International receive reimbursement for all direct and indirect costs incurred in the provisioning of the services. Under the terms of this agreement, in 2010, 2009 and 2008, the Company recorded net charges of $59 million, $233 million and $256 million, respectively.

Certain employees of the Company participate in share-based compensation plans of BP. Under these plans, the employees receive various share-based compensation awards, including share options. For share based plans, the awards granted by BP have an exercise price equal to the market price on the date of grant. The awards are generally exercisable one to three years after the date of grant, and lapse after ten years. Share-based compensation expense allocated to the Company amounted to $228 million ($156 million after tax) in 2010, $208 million ($142 million after tax) in 2009 and $190 million ($130 million after tax) in 2008. The net tax benefits relating to options exercised amounted to $134 million in 2010, $1 million in 2009 and $39 million in 2008.

Note 23 Segment and Geographic Data

The Company operates worldwide in the petroleum industry. The Company's operations comprise three reportable segments. Exploration and Production activities include oil and natural gas exploration, field development and production, natural gas processing and marketing and pipeline transportation. Refining and Marketing activities include oil supply and trading, refining, petrochemicals manufacturing and marketing. Corporate and Other activity is principally comprised of finance, the Company's aluminum business, alternative energy, interest income and costs associated with corporate activities.

In 2010, following the Gulf of Mexico incident, the GCRO was established and equipped with dedicated resources and capabilities to manage all aspects of the Company's response to the incident. This organization reports directly to BP's chief executive and is overseen by a specific new BP board committee; however, it is not a reportable segment.

BP announced that in 2011 it intends to organize its Exploration and Production segment in three functional divisions – Exploration, Developments and Production, integrated through a Strategy and Integration organization. This change will not affect the Company's reportable segments and Exploration and Production will continue to be reported as a single segment.

Intersegment and inter-geographic sales are accounted for at prices that approximate market prices and eliminate upon consolidation. Income taxes are generally assigned to the operations that give rise to the tax effects.

Identifiable assets are those used in the operations of each segment or area, including intersegment or inter-geographic receivables. Corporate assets also include cash, marketable securities, and notes and amounts due from affiliates.

Various adjustments have been made to data in the tables below to conform presentation in all years.

Information by Industry Segment

Millions of Dollars	Exploration and Production	Refining and Marketing	Corporate and Other	Gulf of Mexico oil spill response	Total
Year 2010					
Revenue from external customers	$ 25,423	$ 106,623	$ 1,212	$ -	$ 133,258
Excise taxes	29	11,475	-	-	11,504
Intersegment revenues	11,189	7,575	(9)	-	
Equity in income of affiliates and other	616	472	33	590	1,711
Gain on sale of businesses and fixed assets	4,863	417	3	-	5,283
Total revenues					$ 151,756
Income (loss) before interest and income taxes	$ 18,842	$ 832	$ (403)	$ (32,592)	$ (13,321)
Interest expense			(1,609)		(1,609)
Interest income			177		177
Income tax (provision) benefit	(6,532)	157	(291)	10,030	3,364
Net income (loss)	12,310	989	(2,126)	(22,562)	(11,389)
Net (income) loss attributable to non-controlling interests	(764)	(260)	(4)	-	(1,028)
Net income (loss) attributable to the Company	$ 11,546	$ 729	$ (2,130)	$ (22,562)	$ (12,417)
Investments in affiliates	$ 3,514	$ 2,310	$ 6,220	$ -	$ 12,044
Goodwill	4,283	1,401	75	-	5,759
Other segment assets	101,863	24,886	12,917	-	139,666
Total assets				$	$ 157,469
Depreciation and related charges	$ 7,148	$ 1,351	$ 209	$ -	$ 8,708
Capital expenditures	10,048	3,149	695	-	13,892

Millions of Dollars	Exploration and Production	Refining and Marketing	Corporate and Other	Total
Year 2009, *as Adjusted*				
Revenue from external customers	$ 23,345	$ 85,080	$ 1,040	$ 109,465
Excise taxes	27	10,733	-	10,760
Intersegment revenues	9,196	6,009	(1)	
Equity in income of affiliates and other	758	387	52	1,197
Gain on sale of businesses and fixed assets	1,616	16	57	1,689
Total revenues				$ 123,111
Income (loss) before interest and income taxes	$ 13,144	$ (4,279)	$ (959)	$ 7,906
Interest expense	-	-	(1,139)	(1,139)
Interest income	-	-	198	198
Income tax (provision) benefit	(4,187)	1,620	(487)	(3,054)
Net income (loss)	8,957	(2,659)	(2,387)	3,911
Net (income) loss attributable to non-controlling interests	(670)	(200)	16	(854)
Net income (loss) attributable to the Company	$ 8,287	$ (2,859)	$ (2,371)	$ 3,057
Investments in affiliates	$ 5,949	$ 2,216	$ 640	$ 8,805
Goodwill	4,512	1,476	78	6,066
Other segment assets	95,543	27,250	4,896	127,689
Total assets				$ 142,560
Depreciation and related charges	$ 6,891	$ 1,360	$ 172	$ 8,423
Capital expenditures	11,290	3,009	810	15,109

Millions of Dollars	Exploration and Production	Refining and Marketing	Corporate and Other	Total
Year 2008, *as Adjusted*				
Revenue from external customers	$ 35,847	$ 125,322	$ 1,248	$ 162,417
Excise taxes	75	10,717	-	10,792
Intersegment revenues	11,137	9,585	32	
Equity in income of affiliates and other	756	(56)	12	712
Gain on sale of businesses and fixed assets	19	87	28	134
Total revenues				$ 174,055
Income (loss) before interest and income taxes	$ 23,608	$ 1,120	$ (824)	$ 23,904
Interest expense	-	-	(1,397)	(1,397)
Interest income	-	-	615	615
Income tax (provision) benefit	(9,130)	(236)	268	(9,098)
Net income (loss)	14,478	884	(1,338)	14,024
Net (income) loss attributable to non-controlling interests	(1,351)	50	5	(1,296)
Net income (loss) attributable to the Company	$ 13,127	$ 934	$ (1,333)	$ 12,728
Depreciation and related charges	$ 5,499	$ 1,175	$ 206	$ 6,880
Capital expenditures	12,746	2,846	463	16,055

Information by Geographic Area

	2010		2009		2008
Millions of Dollars	Revenues	Total Assets	Revenues	Total Assets	Revenues
United States	$ 109,228	$ 102,599	$ 89,069	$ 90,509	$ 131,563
Canada	8,701	8,597	4,993	8,746	8,004
Europe	2,161	12,552	2,113	10,405	3,251
Central and South America	3,008	7,606	2,611	7,108	4,876
Other	28,658	26,115	24,325	25,792	26,361
Total	$ 151,756	$ 157,469	$ 123,111	$ 142,560	$ 174,055

Note 24 Goodwill

The changes in carrying amounts of goodwill for the years ended December 31, 2010 and 2009 are as follows:

	Exploration and Production		Refining and Marketing		Corporate And Other		Total	
Millions of Dollars	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Balance at January 1								
Goodwill	$ 4,512	$ 4,512	$ 3,271	$ 3,279	$ 78	$ 79	$ 7,861	$ 7,870
Accumulated impairment	-	-	(1,795)	-	-	-	(1,795)	-
	4,512	4,512	1,476	3,279	78	79	6,066	7,870
Activity during:								
Acquisitions	158	-	-	-	-	-	158	-
Impairment losses	-	-	-	(1,795)	-	-	-	(1,795)
Exchange adjustments	-	-	11	(8)	-	-	11	(8)
Disposals (1)	(334)	-	(86)	-	(3)	(1)	(423)	(1)
Held for sale(1)	(53)	-	-	-	-	-	(53)	-
Balance at December 31								
Goodwill	4,283	4,512	3,196	3,271	75	78	7,554	7,861
Accumulated impairment	-	-	(1,795)	(1,795)	-	-	(1,795)	(1,795)
	$ 4,283	$ 4,512	$ 1,401	$ 1,476	$ 75	$ 78	$ 5,759	$ 6,066

(1) Goodwill has been allocated to assets held for sale and disposals based on the asset's share of the total reporting unit goodwill. Additionally the disposals above include $215 million and $86 million in Exploration and Production and Refining and Marketing, respectively, related to the deconsolidation of BPAGL at December 31, 2010.

Note 25 Exploratory Well Costs

The Company recognized exploration expense in 2010 of $500 million (2009 $725 million and 2008 $484 million). This amount includes $157 million related to decommissioning of Gulf of Mexico idle infrastructure, as required by the Bureau of Ocean Energy Management Regulation and Enforcement's Notice of Lessees 2010 G05 issued in October 2010.

Reserves booking from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling.

Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. If hydrocarbons are found, and, subject to further appraisal activity which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off.

In evaluating whether costs incurred meet the criteria for initial and continued capitalization, management uses two main criteria: (a) that exploration drilling is still under way or firmly planned, or (b) that it either has been determined, or work is under way to determine, that the discovery is economically viable, based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing.

The following table summarizes the changes to the Company's capitalized exploratory well costs. Other reductions represent property sales and disposals. For 2010, other reductions included $101 million relating to the deconsolidation of BPAGL. See Note on Organization and Accounting changes. For 2008, other reductions represent asset transfers to affiliates of BP.

Millions of Dollars	**2010**	**2009**	**2008**
Balance at January 1	$ 1,758	$ 1,407	$ 1,413
Additions pending a determination of proved reserves	613	644	430
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(189)	(54)	(44)
Capitalized exploratory well costs charged to expense	(26)	(239)	(16)
Other reductions	(240)	-	(376)
Balance at December 31	$ 1,916	$ 1,758	$ 1,407

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

Millions of Dollars - December 31	2010		2009		2008	
	Cost	Wells Gross	Cost	Wells Gross	Cost	Wells Gross
Capitalized for a period of:						
One year or less	$ 534	32	$ 460	14	$ 433	22
One to five years	1,199	26	1,044	41	802	45
Six to ten years	65	8	127	13	58	10
Greater than ten years	118	27	127	30	114	26
	$ 1,916	93	$ 1,758	98	$ 1,407	103
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year	27		27		28	

The following tables provide an analysis of the amount of drilling costs directly associated with exploration wells.

Millions of Dollars - December 31	2010		
	Cost	Wells Gross	Projects
Projects with first capitalized exploration well drilled in the twelve months ended December 31	$ 366	23	6
Other projects with recent or planned drilling activity	1,225	34	14
Projects with completed exploration activity	325	36	13
	$ 1,916	93	33

Millions of Dollars - December 31	2009		
	Cost	Wells Gross	Projects
Projects with first capitalized exploration well drilled in the twelve months ended December 31	$ 445	16	8
Other projects with recent or planned drilling activity	725	35	9
Projects with completed exploration activity	588	47	18
	$ 1,758	98	35

Millions of Dollars - December 31		2008	
		Wells	
	Cost	Gross	Projects
Projects with first capitalized exploration well drilled in the twelve months ended December 31	$ 184	11	2
Other projects with recent or planned drilling activity	657	46	10
Projects with completed exploration activity	566	46	18
	$ 1,407	103	30

Exploration projects frequently involve the drilling of multiple wells over a number of years, and several discoveries may be grouped into a single development project. At December 31, 2010, the Company had a total of 27 projects with exploration well-drilling costs that have been capitalized for more than twelve months. Of these, there are 14 projects where exploratory wells have been drilled in the preceding twelve months or further exploratory drilling is planned in the next year. Projects with completed exploratory activity comprise a total of 13 projects whose costs totaled $325 million at December 31, 2010. Details of the activities being undertaken to progress these projects towards development are shown below.

Country / Project		Amount Capitalized at December 31, 2010	Number of wells Drilled	Years wells Drilled	Anticipated year of Booking	Comments(1)
		Millions				
Angola						
Chumbo	$	26	3	2003-2005	2012	Development option identified and under evaluation; development plan for FPSO identified.
Cesio		28	2	2003	2012	Development option identified and under evaluation.
Indonesia						
Tangguh Phase II		51	9	1994-1997	2013-2014	Assessment of economic and developmental aspects of project in progress; onshore and offshore development options identified and under evaluation.
Norway						
Arundel		25	2	2008	2011	Development options identified and under evaluation.
Puffin		29	9	1982-1991	2011-2014	Assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing infrastructure.
Trinidad						
Coconut		47	1	2005	2014	Assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing infrastructure.
Corallita/ Lantana		24	2	1996	2011-2014	Development options identified and under evaluation; planned subsea tieback to existing infrastructure fields dedicated to LNG gas contract delivery.
Manakin		21	1	2000	2013-2018	Assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing production facilities and LNG train; inter-governmental discussions on unitization continue.
United States						
Milne Point - NW Schrader		13	2	2007	2013	Development option identified and under evaluation.
Mad Dog Deep		48	1	2005	2013	Assessment of economic and developmental aspects of project in progress; development anticipated to be by tieback to existing infrastructure.
Other		13	4			
Total (13 projects)	$	325	36			

(1) For all projects above the assessment of hydrocarbon quantities as potentially commercial has been completed.

The following projects which were classified as projects with completed exploration activity at December 31, 2009 were not disclosed due to the following reasons:

- Project Tubular Bells was sanctioned for development in 2010.
- Project Mad Dog SWR was sanctioned for development in 2010.

Note 26 Subsequent Events (Unaudited)

On January 20, 2011, the Company completed the sale of four mature producing deepwater oil and gas fields in the US Gulf of Mexico to Marubeni Oil and Gas for an adjusted purchase price of $571 million. See Note 4 and Note 7.

On February 1, 2011, the Company announced that, following a strategic review, it intends to divest the Texas City refinery and the southern part of its US West Coast fuels value chain, including the Carson refinery, by the end of 2012 subject to all necessary legal and regulatory approvals. The Company will ensure current obligations at Texas City are fulfilled. The assets do not yet meet the criteria to be reclassified as non-current assets held for sale and it is not yet possible to estimate the financial effect of these intended transactions.

On February 9, 2011, the Company announced that it had exercised its preferential rights to purchase, from Shell, various equity interests (11.5% - 25%) in the Gulf of Mexico Marlin and Dorado platforms for $257 million. With this acquisition, the Company now owns 100 percent of the Marlin and Dorado platforms.

On February 15, 2011, the Company completed its first quarter 2011 installment funding of the Deepwater Horizon Oil Spill Trust (the trust) in the amount of $1,250 million. As of this date, the Company has a remaining commitment to the trust of $13,750 million, to be paid in quarterly installments until the end of 2013.

On February 22, 2011, the Company announced its intention to sell its interests in a number of operated oil and gas fields in the UK. The assets include the Company's operated gas fields in the southern North Sea. The Company aims to complete the divestments around the end of 2011, subject to receipt of suitable offers and regulatory and third party approvals. The assets do not yet meet the criteria to be reclassified as assets held for sale and it is not yet possible to estimate the financial effect of these intended transactions.

On March 18, 2011, the Company signed a definitive agreement with Buckeye Partners to sell certain US petroleum products terminals and pipelines for $225 million, subject to closing adjustments. The proposed sale includes the Company's interest in Inland Corporation. The transaction is expected to close in the second quarter of 2011, subject to regulatory approvals, other customary closing conditions, and, with respect to the Company's interest in Inland, other co-owners' pre-emption rights.

On March 23, 2011, the Company announced that it had agreed to sell its 93 percent interest in the Wattenberg, Colorado natural gas processing plant to a wholly-owned subsidiary of Anadarko Petroleum Corporation for $576 million, subject to closing adjustments.

As of March 23, 2011 new lines of credit facilities are being finalized that will replace all but $650 million of the current line of credit facilities totaling $12,500 million (see Note 11). The new facilities will be of three year duration and total $6,825 million.

BP AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION
(UNAUDITED)

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The tables that follow provide supplemental information about oil and gas exploration and production activities. This information excludes activities associated with the marketing of natural gas.

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Results of Operations for Oil and Gas Producing Activities

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2010						
Consolidated Entities						
Oil and gas production revenues:						
From consolidated subsidiaries	$ 1,149	$ 90	$ 1,849	$ -	$ 4,437	$ 7,525
From unconsolidated affiliate and unaffiliated entities	18,820	453	1,072	-	4,085	24,430
Other income	2,350	2,183	-	-	332	4,865
Total revenues	22,319	2,726	2,921	-	8,854	36,820
Production costs:						
Taxes other than income	1,093	2	249	-	142	1,486
Other production costs	2,974	205	319	1	1,250	4,749
Exploration expenses	465	3	8	-	24	500
Depreciation, depletion and amortization expense	4,500	90	451	-	1,587	6,628
Other costs (income)	3,454	(36)	131	12	368	3,929
Total costs	12,486	264	1,158	13	3,371	17,292
Operating profit	9,833	2,462	1,763	(13)	5,483	19,528
Income tax expense (benefit)	3,292	599	1,007	-	1,978	6,876
Results of operations	6,541	1,863	756	(13)	3,505	12,652
Result of operations attributable to non-controlling interests	1	-	214	-	546	761
Result of operations attributable to the Company	$ 6,540	$ 1,863	$ 542	$ (13)	$ 2,959	$ 11,891
Company Share of Equity Accounted Entities						
Oil and gas production revenues:						
From consolidated subsidiaries	$ -	$ -	$ -	$ 2,000	$ 87	$ 2,087
From unconsolidated affiliate and unaffiliated entities	-	-	-	-	19	19
Other income	-	-	-	-	-	-
Total revenues	-	-	-	2,000	106	2,106
Production costs:						
Taxes other than income	-	-	-	812	-	812
Other production costs	-	-	-	302	11	313
Exploration expenses	-	-	-	22	-	22
Depreciation, depletion and amortization expense	-	-	-	256	30	286
Other costs (income)	-	67	-	72	-	139
Total costs	-	67	-	1,464	41	1,572
Operating profit	-	(67)	-	536	65	534
Income tax expense	-	-	-	196	33	229
Results of operations attributable to the Company	$ -	$ (67)	$ -	$ 340	$ 32	$ 305
Total Consolidated and Equity Accounted Entities Results of Operations	$ 6,540	$ 1,796	$ 542	$ 327	$ 2,991	$ 12,196

BP AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2009						
Consolidated Entities						
Oil and gas production revenues:						
From consolidated subsidiaries	$ 4,750	$ 83	$ 1,544	$ -	$ 3,200	$ 9,577
From unconsolidated affiliate and unaffiliated entities	11,292	408	877	6	3,972	16,555
Other income	209	-	-	-	1,401	1,610
Total revenues	16,251	491	2,421	6	8,573	27,742
Production costs:						
Taxes other than income	644	1	220	-	81	946
Other production costs	2,947	298	318	-	1,007	4,570
Exploration expenses	663	19	10	-	33	725
Depreciation, depletion and amortization expense	3,913	167	441	-	1,841	6,362
Other costs (income)	2,302	(5)	128	19	318	2,762
Total costs	10,469	480	1,117	19	3,280	15,365
Operating profit	5,782	11	1,304	(13)	5,293	12,377
Income tax expense (benefit)	1,862	(65)	881	-	880	3,558
Results of operations	3,920	76	423	(13)	4,413	8,819
Result of operations attributable to non-controlling interests	1	-	115	-	528	644
Result of operations attributable to the Company	$ 3,919	$ 76	$ 308	$ (13)	$ 3,885	$ 8,175
Company Share of Equity Accounted Entities						
Oil and gas production revenues:						
From consolidated subsidiaries	$ -	$ -	$ -	$ 1,778	$ -	$ 1,778
From unconsolidated affiliate and unaffiliated entities	-	-	-	-	-	-
Other income	-	-	-	-	-	-
Total revenues	-	-	-	1,778	-	1,778
Production costs:						
Taxes other than income	-	-	-	634	-	634
Other production costs	-	-	-	325	-	325
Exploration expenses	-	-	-	23	-	23
Depreciation, depletion and amortization expense	-	-	-	266	-	266
Other costs (income)	-	-	-	(79)	-	(79)
Total costs	-	-	-	1,169	-	1,169
Operating profit	-	-	-	609	-	609
Income tax expense	-	-	-	253	-	253
Results of operations attributable to the Company	$ -	$ -	$ -	$ 356	$ -	$ 356
Total Consolidated and Equity Accounted Entities Results of Operations	$ 3,919	$ 76	$ 308	$ 343	$ 3,885	$ 8,531

BP AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2008						
Oil and gas production revenues:						
From consolidated subsidiaries	$ 8,013	$ 147	$ 3,005	$ -	$ 4,681	$ 15,846
From unconsolidated affiliate and unaffiliated entities	15,615	1,236	1,973	1	5,086	23,911
Other income	22	(2)	-	-	-	20
Total revenues	23,650	1,381	4,978	1	9,767	39,777
Production costs:						
Taxes other than income	2,613	2	347	-	235	3,197
Other production costs	3,457	301	352	-	1,480	5,590
Exploration expenses	305	30	9	-	140	484
Depreciation, depletion and amortization expense	3,131	181	443	-	1,583	5,338
Other costs	3,383	233	167	14	(95)	3,702
Total costs	12,889	747	1,318	14	3,343	18,311
Operating profit	10,761	634	3,660	(13)	6,424	21,466
Income tax expense (benefit)	4,005	129	2,158	(2)	2,634	8,924
Results of operations	6,756	505	1,502	(11)	3,790	12,542
Results of operations attributable to non-controlling interests	-	-	461	-	679	1,140
Results of operations attributable to the Company	$ 6,756	$ 505	$ 1,041	$ (11)	$ 3,111	$ 11,402
Company Share of Equity Accounted Entities						$ 528

Oil and gas production revenues reflect the market prices of net production sold or transferred, with appropriate adjustments for royalties, net profits interest and other contractual provisions. Gains or losses resulting from divestments of assets or businesses are included in other income. Taxes other than income include production and severance taxes. Other production costs are lifting costs incurred to operate and maintain productive wells and related equipment, including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Also included are operating costs of field natural gas liquids plants. Production costs include related administrative expenses and depreciation applicable to support equipment associated with production activities.

Exploration expenses include the costs of geological and geophysical activity, carrying and retaining undeveloped properties and drilling exploratory wells determined to be non-productive. Depreciation, depletion and amortization expense relates to capitalized costs incurred in acquisition, exploration and development activities and does not include depreciation applicable to support equipment. Included in other related costs are significant, non-recurring items and purchases of natural gas for field natural gas liquids plants.

Income taxes are generally assigned to the operations that give rise to the tax effects. Results of operations do not include interest expense and general corporate amounts nor their associated tax effects.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows was computed through 2008 by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. Beginning in 2009, the standardized measure of discounted future net cash flows is computed by applying first day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. The standardized measure includes costs for future dismantlement, abandonment and rehabilitation obligations. The Company believes the standardized measure does not provide a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Summarized on the following pages is the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2010, 2009 and 2008. The amounts shown for equity accounted entities represents the Company's proportionate economic interest in the estimated discounted future net cash flows of equity accounted investments.

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars		United States		Other Countries in North America		Trinidad		Other Countries in South America		Other Countries and Continents		Total
December 31, 2010												
Consolidated Entities												
Future cash inflows	$	264,802	$	225	$	26,431	$	-	$	66,821	$	358,279
Future development and production costs		135,746		173		12,056		-		30,878		178,853
Future income taxes		41,892		16		7,661		-		14,802		64,371
Future net cash flows		87,164		36		6,714		-		21,141		115,055
Ten percent annual discount		45,499		2		2,836		-		7,890		56,227
Discounted net cash flows	$	41,665	$	34	$	3,878	$	-	$	13,251	$	58,828
Company Share of Equity Accounted Entities												
Future cash inflows	$	-	$	9,681	$	-	$	33,748	$	500	$	43,929
Future development and production costs		-		6,585		-		17,725		142		24,452
Future income taxes		-		751		-		4,459		174		5,384
Future net cash flows		-		2,345		-		11,564		184		14,093
Ten percent annual discount		-		2,345		-		6,900		43		9,288
Discounted net cash flows	$	-	$	-	$	-	$	4,664	$	141	$	4,805
Total Consolidated and Equity Accounted Entities' Discounted Future Cash Flows	$	41,665	$	34	$	3,878	$	4,664	$	13,392	$	63,633

The above includes future net cash flows for assets held for sale at December 31, 2010.

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars		United States		Other Countries in North America		Trinidad		Other Countries in South America		Other Countries and Continents		Total
December 31, 2009												
Consolidated Entities												
Future cash inflows	$	204,019	$	4,865	$	24,351	$	-	$	77,739	$	310,974
Future development and production costs		116,236		3,694		11,330		-		36,443		167,703
Future income taxes		27,298		171		5,658		-		13,283		46,410
Future net cash flows		60,485		1,000		7,363		-		28,013		96,861
Ten percent annual discount		29,539		474		2,955		-		12,193		45,161
Discounted net cash flows	$	30,946	$	526	$	4,408	$	-	$	15,820	$	51,700
Company Share of Equity Accounted Entities												
Future cash inflows	$	-	$	-	$	-	$	29,227	$	315	$	29,542
Future development and production costs		-		-		-		16,290		130		16,420
Future income taxes		-		-		-		3,323		86		3,409
Future net cash flows		-		-		-		9,614		99		9,713
Ten percent annual discount		-		-		-		5,622		26		5,648
Discounted net cash flows	$	-	$	-	$	-	$	3,992	$	73	$	4,065
Total Consolidated and Equity Accounted Entities' Discounted Future Cash Flows	$	30,946	$	526	$	4,408	$	3,992	$	15,893	$	55,765

BP AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
December 31, 2008						
Future cash inflows	$ 165,728	$ 6,417	$ 24,655	$ -	$ 63,501	$ 260,301
Future development and production costs	105,980	3,987	13,381	-	36,968	160,316
Future income taxes	17,460	513	5,464	-	9,175	32,612
Future net cash flows	42,288	1,917	5,810	-	17,358	67,373
Ten percent annual discount	20,990	984	2,791	-	8,078	32,843
Discounted net cash flows	$ 21,298	$ 933	$ 3,019	$ -	$ 9,280	$ 34,530
Company Share of Equity Accounted Entities						$ 3,911

Non-controlling interest share of consolidated entities discounted future net cash flows in Trinidad and Other Countries and Continents approximated $1,163 million and $2,915 million in 2010, $1,322 million and $3,550 million in 2009 and $906 million and $1,994 million in 2008, respectively. Future cash inflows were computed with prices used in estimating the Company's (or the investee's) proved oil and gas reserves as reported under "Estimated Quantities of Proved Oil and Gas Reserves". Future price changes are considered only to the extent provided by contractual arrangements.

Statement of Changes in Standardized Measure of Discounted Future Net Cash Flows

The following tables detail the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2010 and 2009, respectively.

Millions of Dollars	Consolidated Entities	Company Share of Equity Accounted Entities	Total Consolidated and Equity Accounted Entities
Balance at January 1, 2010	$ 51,700	$ 4,065	$ 55,765
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	(17,625)	(1,064)	(18,689)
Net changes in prices, and development and production costs	31,250	1,147	32,397
Current year expenditures for development	6,566	514	7,080
Extensions, discoveries and improved recovery, less related costs	4,854	327	5,181
Net change due to purchases and sales of minerals in place (a)	(9,769)	-	(9,769)
Revisions of previous quantity estimates	(4,476)	(142)	(4,618)
Accretion of discount	5,170	406	5,576
Net change in income taxes	(8,514)	(461)	(8,975)
Other	(328)	13	(315)
Balance at December 31, 2010	$ 58,828	$ 4,805	$ 63,633

(a) Includes balances related to the BPAGL deconsolidation. See Note on Organization and Accounting changes for further information.

Millions of Dollars	Consolidated Entities	Company Share of Equity Accounted Entities	Total Consolidated and Equity Accounted Entities
Balance at January 1, 2009	$ 34,530	$ 3,911	$ 38,441
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	(13,085)	(913)	(13,998)
Net changes in prices, and development and production costs	17,672	392	18,064
Current year expenditures for development	7,429	561	7,990
Extensions, discoveries and improved recovery, less related costs	3,667	645	4,312
Net change due to purchases and sales of minerals in place	(89)	(869)	(958)
Revisions of previous quantity estimates	3,417	(133)	3,284
Accretion of discount	3,453	391	3,844
Net change in income taxes	(6,066)	82	(5,984)
Other	772	(2)	770
Balance at December 31, 2009	$ 51,700	$ 4,065	$ 55,765

SUPPLEMENTAL INFORMATION
(UNAUDITED)

The following table details the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2008.

Millions of Dollars		
Balance at January 1, 2008	$	102,565
Changes resulting from:		
Sales and transfers of oil and gas produced, net of production costs		(26,733)
Net changes in prices, and development and production costs		(105,775)
Current year expenditures for development		8,091
Extensions, discoveries and improved recovery, less related costs		2,845
Net change due to purchases and sales of minerals in place		168
Revisions of previous quantity estimates		(4,741)
Accretion of discount		10,257
Net change in income taxes		49,180
Other		(1,327)
Balance at December 31, 2008	$	34,530

The prices of crude oil and natural gas have fluctuated over the past several years, which affects the computed future cash flows over the period shown. Because the price of crude oil and natural gas is likely to remain volatile in the future, price changes can be expected to continue to significantly affect the standardized measure of discounted future net cash flows.

Estimated Quantities of Proved Oil and Gas Reserves

Estimated proved reserve quantities of crude oil (including condensate), NGL and natural gas at the beginning and end of 2010, 2009 and 2008, with the detail of changes during those years, are presented on the following pages. Reported quantities include reserves in which the Company holds an interest under production-sharing and other types of operating agreements with foreign governments. The estimates were prepared by BP group engineers and are based on current technology and economic conditions. The Company considers such estimates to be reasonable and consistent with current knowledge of the characteristics and extent of proved production. These estimates include only those amounts considered to be proved reserves and do not include additional amounts that may result from extensions of currently proved areas, or amounts that may result from new discoveries in the future, or from application of secondary or tertiary recovery processes not yet determined to be commercial. Proved oil and gas reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulation before the time at which the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods (or in which the cost of the required equipment is relatively minor compared to the cost of a new well) or through installed extraction equipment and infrastructure operational at the time of the reserve estimate if extraction is by means not involving a well.

The amounts shown for equity accounted entities represent the Company's proportionate interest in the estimated proved reserves of equity accounted investments.

The Company estimates of proved reserves for 2010 and 2009 are based on a 12 month average price. Estimates of proved reserves for 2008 reflect year end prices.

Crude Oil and NGL Reserves

Millions of Barrels	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2010						
Consolidated Entities						
At January 1, 2010						
Developed	1,862	11	32	-	344	2,249
Undeveloped	1,211	1	44	-	313	1,569
	3,073	12	76	-	657	3,818
Changes attributable to:						
Revisions of previous estimates	(45)	1	-	-	(13)	(57)
Improved recovery	133	-	8	-	25	166
Discoveries and extensions	80	-	-	-	3	83
Purchases of reserves in place	6	-	-	-	33	39
Sales of reserves in place	(117)	(11)	-	-	(108)	(236)
Production	(211)	(2)	(12)	-	(65)	(290)
	(154)	(12)	(4)	-	(125)	(295)
At December 31, 2010						
Developed	1,729	-	28	-	268	2,025
Undeveloped	1,190	-	44	-	264	1,498
	2,919	-	72	-	532	3,523
Company Share of Equity Accounted Entities						
At January 1, 2010						
Developed	-	-	-	354	1	355
Undeveloped	-	-	-	270	-	270
	-	-	-	624	1	625
Changes attributable to:						
Revisions of previous estimates	-	-	-	(5)	-	(5)
Improved recovery	-	-	-	33	-	33
Discoveries and extensions	-	-	-	-	-	-
Sales of reserves in place	-	-	-	-	-	-
Production	-	-	-	(28)	-	(28)
	-	-	-	-	-	-
At December 31, 2010						
Developed	-	-	-	347	1	348
Undeveloped	-	-	-	277	-	277
	-	-	-	624	1	625
Total consolidated and equity accounted entities						
At January 1, 2010						
Developed	1,862	11	32	354	345	2,604
Undeveloped	1,211	1	44	270	313	1,839
	3,073	12	76	624	658	4,443
At December 31, 2010						
Developed	1,729	-	28	347	269	2,373
Undeveloped	1,190	-	44	277	264	1,775
	2,919	-	72	624	533	4,148

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2010 amounted to 22 and 182 million barrels of crude oil, respectively.

Total subsidiaries and equity accounted entities includes 628 million barrels relating to assets held for sale at December 31 2010. Amounts by continent are: 6 million barrels in the US; 609 million barrels in Other Countries in South America; and 13 million barrels in Other Countries and Continents.

The sales of reserves in place include 93 million barrels related to Australian entities that are no longer consolidated by the Company. See Note on Organization and Accounting changes for further information.

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Natural Gas Reserves

Billions of Cubic Feet	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2010						
Consolidated Entities						
At January 1, 2010						
Developed	9,583	716	3,033	-	4,822	18,154
Undeveloped	5,633	453	7,347	-	4,497	17,930
	15,216	1,169	10,380	-	9,319	36,084
Changes attributable to:						
Revisions of previous estimates	(1,854)	(11)	(2)	-	(151)	(2,018)
Improved recovery	830	-	468	-	189	1,487
Discoveries and extensions	739	9	20	-	114	882
Purchases of reserves in place	97	1	-	-	31	129
Sales of reserves in place	(424)	(1,033)	-	-	(2,696)	(4,153)
Production	(861)	(77)	(920)	-	(658)	(2,516)
	(1,473)	(1,111)	(434)	-	(3,171)	(6,189)
At December 31, 2010				-		
Developed	9,495	58	3,417	-	4,232	17,202
Undeveloped	4,248	-	6,529	-	1,916	12,693
	13,743	58	9,946	-	6,148	29,895
Company Share of Equity Accounted Entities						
At January 1, 2010						
Developed	-	-	-	1,235	39	1,274
Undeveloped	-	-	-	973	13	986
	-	-	-	2,208	52	2,260
Changes attributable to:						
Revisions of previous estimates	-	-	-	(135)	(2)	(137)
Improved recovery	-	-	-	291	11	302
Discoveries and extensions	-	-	-	23	-	23
Production	-	-	-	(165)	(12)	(177)
	-	-	-	14	(3)	11
At December 31, 2010						
Developed	-	-	-	1,058	30	1,088
Undeveloped	-	-	-	1,164	19	1,183
	-	-	-	2,222	49	2,271
Total consolidated and equity accounted entities						
At January 1, 2010						
Developed	9,583	716	3,033	1,235	4,861	19,428
Undeveloped	5,633	453	7,347	973	4,510	18,916
	15,216	1,169	10,380	2,208	9,371	38,344
At December 31, 2010						
Developed	9,495	58	3,417	1,058	4,262	18,290
Undeveloped	4,248	-	6,529	1,164	1,935	13,876
	13,743	58	9,946	2,222	6,197	32,166

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2010 amounted to 2,921 and 666 billion cubic feet of natural gas, respectively.

Total subsidiaries and equity accounted entities includes 2,064 billion cubic feet relating to assets held for sale at December 31, 2010. Amounts by continent are: 158 billion cubic feet in the US; 1,773 billion cubic feet in Other Countries in South America; and 133 billion cubic feet in Other Countries and Continents.

The sales of reserves in place include 2,644 billion cubic feet related to Australian entities that are no longer consolidated by the Company. See Note on Organization and Accounting changes for further information.

SUPPLEMENTAL INFORMATION
(UNAUDITED)

Bitumen Reserves

For The Year Ended December 31, 2010		
Millions of Barrels	**Other Countries in North America**	**Total**
Equity-accounted entities (BP share)		
At 1 January 2010		
Developed	-	-
Undeveloped	-	-
	-	-
Changes attributable to		
Revisions of previous estimates	-	-
Improved recovery	-	-
Discoveries & extensions	179	179
Sales of reserves in place	-	-
Production	-	-
	179	179
At 31 December 2010		
Developed	-	-
Undeveloped	179	179
	179	179

Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

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SUPPLEMENTAL INFORMATION (UNAUDITED)

Crude Oil and NGL Reserves

Millions of Barrels	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2009						
Consolidated Entities						
At January 1, 2009						
Developed	1,717	12	25	-	360	2,114
Undeveloped	1,273	1	45	-	347	1,666
	2,990	13	70	-	707	3,780
Changes attributable to:						
Revisions of previous estimates	165	1	18	-	(10)	174
Improved recovery	82	-	1	-	46	129
Extensions, discoveries and other changes	73	-	-	-	10	83
Sales of reserves in place	-	-	-	-	(27)	(27)
Production	(237)	(2)	(13)	-	(69)	(321)
	83	(1)	6	-	(50)	38
At December 31, 2009						
Developed	1,862	11	32	-	344	2,249
Undeveloped	1,211	1	44	-	313	1,569
	3,073	12	76	-	657	3,818
Company Share of Equity Accounted Entities						
At January 1, 2009						
Developed	-	-	-	341	66	407
Undeveloped	-	-	-	272	56	328
	-	-	-	613	122	735
Changes attributable to:						
Revisions of previous estimates	-	-	-	2	(1)	1
Improved recovery	-	-	-	50	-	50
Extensions, discoveries and other changes	-	-	-	3	-	3
Sales of reserves in place	-	-	-	(14)	(116)	(130)
Production	-	-	-	(30)	(4)	(34)
	-	-	-	11	(121)	(110)
At December 31, 2009						
Developed	-	-	-	354	1	355
Undeveloped	-	-	-	270	-	270
	-	-	-	624	1	625
Total Consolidated and Equity Accounted Entities						
At January 1, 2009						
Developed	1,717	12	25	341	426	2,521
Undeveloped	1,273	1	45	272	403	1,994
	2,990	13	70	613	829	4,515
At December 31, 2009						
Developed	1,862	11	32	354	345	2,604
Undeveloped	1,211	1	44	270	313	1,839
	3,073	12	76	624	658	4,443

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2009 amounted to 23 and 208 million barrels of crude oil, respectively.

Natural Gas Reserves

Billions of Cubic Feet	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2009						
Consolidated Entities						
At January 1, 2009						
Developed	9,049	659	3,129	-	3,711	16,548
Undeveloped	5,483	468	7,380	-	5,905	19,236
	14,532	1,127	10,509	-	9,616	35,784
Changes attributable to:						
Revisions of previous estimates	549	44	341	-	150	1,084
Improved recovery	550	5	322	-	205	1,082
Extensions, discoveries and other changes	496	94	105	-	120	815
Purchases of reserves in place	-	-	-	-	143	143
Sales of reserves in place	(4)	-	-	-	(297)	(301)
Production	(907)	(101)	(897)	-	(618)	(2,523)
	684	42	(129)	-	(297)	300
At December 31, 2009						
Developed	9,583	716	3,033	-	4,822	18,154
Undeveloped	5,633	453	7,347	-	4,497	17,930
	15,216	1,169	10,380	-	9,319	36,084
Company Share of Equity Accounted Entities						
At January 1, 2009						
Developed	-	-	-	1,480	129	1,609
Undeveloped	-	-	-	985	112	1,097
	-	-	-	2,465	241	2,706
Changes attributable to:						
Revisions of previous estimates	-	-	-	(26)	(20)	(46)
Improved recovery	-	-	-	314	4	318
Extensions, discoveries and other changes	-	-	-	6	-	6
Sales of reserves in place	-	-	-	(387)	(154)	(541)
Production	-	-	-	(164)	(19)	(183)
	-	-	-	(257)	(189)	(446)
At December 31, 2009						
Developed	-	-	-	1,235	39	1,274
Undeveloped	-	-	-	973	13	986
	-	-	-	2,208	52	2,260
Total Consolidated and Equity Accounted Entities						
At January 1, 2009						
Developed	9,049	659	3,129	1,480	3,840	18,157
Undeveloped	5,483	468	7,380	985	6,017	20,333
	14,532	1,127	10,509	2,465	9,857	38,490
At December 31, 2009						
Developed	9,583	716	3,033	1,235	4,861	19,428
Undeveloped	5,633	453	7,347	973	4,510	18,916
	15,216	1,169	10,380	2,208	9,371	38,344

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2009 amounted to 3,068 and 1,384 billion cubic feet of natural gas, respectively.

Crude Oil and NGL Reserves

Millions of Barrels	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2008						
Consolidated Entities						
At January 1, 2008						
Developed	1,882	13	28	-	309	2,232
Undeveloped	1,265	3	41	-	317	1,626
	3,147	16	69	-	626	3,858
Changes attributable to:						
Revisions of previous estimates	(212)	(1)	9	-	90	(114)
Improved recovery	182	-	-	-	53	235
Extensions, discoveries and other changes	64	1	5	-	6	76
Sales of reserves in place	-	-	-	-	-	-
Production	(191)	(3)	(13)	-	(68)	(275)
	(157)	(3)	1	-	81	(78)
At December 31, 2008						
Developed	1,717	12	25	-	360	2,114
Undeveloped	1,273	1	45	-	347	1,666
	2,990	13	70	-	707	3,780
Company Share of Equity Accounted Entities						
At January 1, 2008						
Developed	-	-	-	328	70	398
Undeveloped	-	-	-	243	55	298
	-	-	-	571	125	696
Changes attributable to:						
Revisions of previous estimates	-	-	-	26	-	26
Improved recovery	-	-	-	32	-	32
Extensions, discoveries and other changes	-	-	-	13	-	13
Sales of reserves in place	-	-	-	-	-	-
Production	-	-	-	(29)	(3)	(32)
	-	-	-	42	(3)	39
At December 31, 2008						
Developed	-	-	-	341	66	407
Undeveloped	-	-	-	272	56	328
	-	-	-	613	122	735
Total Consolidated and Equity Accounted Entities						
At January 1, 2008						
Developed	1,882	13	28	328	379	2,630
Undeveloped	1,265	3	41	243	372	1,924
	3,147	16	69	571	751	4,554
At December 31, 2008						
Developed	1,717	12	25	341	426	2,521
Undeveloped	1,273	1	45	272	403	1,994
	2,990	13	70	613	829	4,515

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2008 amounted to 21 and 212 million barrels of crude oil, respectively.

Natural Gas Reserves

Billions of Cubic Feet	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
2008						
Consolidated Entities						
At January 1, 2008						
Developed	10,670	608	2,865	-	3,108	17,251
Undeveloped	4,704	421	7,839	-	6,370	19,334
	15,374	1,029	10,704	-	9,478	36,585
Changes attributable to						
Revisions of previous estimates	(2,062)	52	(327)	-	522	(1,815)
Improved recovery	1,322	16	109	-	115	1,562
Extensions, discoveries and other changes	549	124	948	-	58	1,679
Purchases of reserves in place	183	-	-	-	-	183
Sales of reserves in place	-	-	-	-	-	-
Production	(834)	(94)	(925)	-	(557)	(2,410)
	(842)	98	(195)	-	138	(801)
At 31 December 31, 2008						
Developed	9,049	659	3,129	-	3,711	16,548
Undeveloped	5,483	468	7,380	-	5,905	19,236
	14,532	1,127	10,509	-	9,616	35,784
Company Share of Equity Accounted Entities						
At January 1, 2008						
Developed	-	-	-	1,474	136	1,610
Undeveloped	-	-	-	830	112	942
	-	-	-	2,304	248	2,552
Changes attributable to						
Revisions of previous estimates	-	-	-	(146)	(1)	(147)
Improved recovery	-	-	-	300	11	311
Extensions, discoveries and other changes	-	-	-	192	-	192
Sales of reserves in place	-	-	-	-	-	-
Production	-	-	-	(185)	(17)	(202)
	-	-	-	161	(7)	154
At December 31, 2008						
Developed	-	-	-	1,480	129	1,609
Undeveloped	-	-	-	985	112	1,097
	-	-	-	2,465	241	2,706
Total Consolidated and Equity Accounted Entities						
At January 1, 2008						
Developed	10,670	608	2,865	1,474	3,244	18,861
Undeveloped	4,704	421	7,839	830	6,482	20,276
	15,374	1,029	10,704	2,304	9,726	39,137
At December 31, 2008						
Developed	9,049	659	3,129	1,480	3,840	18,157
Undeveloped	5,483	468	7,380	985	6,017	20,333
	14,532	1,127	10,509	2,465	9,857	38,490

Non-controlling interest share of consolidated entities proved reserves in Trinidad and Other Countries and Continents at December 31, 2008 amounted to 3,108 and 1,243 billion cubic feet of natural gas, respectively.

Capitalized Costs

The following table summarizes capitalized costs for oil and gas exploration and production activities, and the related accumulated depreciation, depletion and amortization.

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
December 31, 2010						
Consolidated Entities						
Unproved properties						
Gross assets	$ 5,968	$ 1,323	$ 220	$ -	$ 2,405	$ 9,916
Accumulated amortization	301	15	-	-	3	319
Net assets	5,667	1,308	220	-	2,402	9,597
Proved properties						
Gross assets	73,750	272	5,945	-	29,125	109,092
Accumulated depreciation and depletion	38,307	200	3,255	-	17,615	59,377
Net assets	35,443	72	2,690	-	11,510	49,715
Net capitalized costs	$ 41,110	$ 1,380	$ 2,910	$ -	$ 13,912	$ 59,312
Company Share of Equity accounted Entities (a)						
Unproved properties						
Proved properties	$ -	$ 142	$ -	$ 103	$ 639	$ 884
Unproved properties	-	1,284	-	-	-	1,284
Accumulated depreciation and depletion	-	-	-		575	575
Net capitalized costs	$ -	$ 1,426	$ -	$ 103	$ 64	$ 1,593

(a) Excludes balances associated with assets held for sale

Non-controlling interest share of net capitalized costs of consolidated entities in Trinidad and Other Countries and Continents at December 31, 2010 amounted to $866 million and $3,966 million, respectively.

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SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
December 31, 2009						
Consolidated Entities						
Unproved properties						
Gross assets	$ 5,464	$ 142	$ 198	$ -	$ 1,401	$ 7,205
Accumulated amortization	226	48	19	-	3	296
Net assets	5,238	94	179	-	1,398	6,909
Proved properties						
Gross assets	70,967	3,905	5,646	(1)	30,653	111,170
Accumulated depreciation and depletion	35,922	2,252	2,803	(1)	19,099	60,075
Net assets	35,045	1,653	2,843	-	11,554	51,095
Net capitalized costs	$ 40,283	$ 1,747	$ 3,022	$ -	$ 12,952	$ 58,004
Company Share of Equity accounted Entities						
Unproved properties						
Gross assets	$ -	$ 1,378	$ -	$ 197	$ -	$ 1,575
Accumulated amortization	-	-	-	-	-	-
Net assets	-	1,378	-	197	-	1,575
Proved properties						
Gross assets	-	-	-	5,592	-	5,592
Accumulated depreciation and depletion	-	-	-	2,051	-	2,051
Net assets	-	-	-	3,541	-	3,541
Net capitalized costs	$ -	$ 1,378	$ -	$ 3,738	$ -	$ 5,116

Non-controlling interest share of net capitalized costs of consolidated entities in Trinidad and Other Countries and Continents at December 31, 2009 amounted to $874 million and $3,090 million, respectively.

SUPPLEMENTAL INFORMATION
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Costs Incurred

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire oil and gas properties. Exploration costs include the costs of geological and geophysical activity, carrying and retaining undeveloped properties and drilling and equipping exploratory wells. Development costs include the costs of drilling and equipping development wells, CO_2 and certain other injected materials for enhanced recovery projects and facilities to extract, treat and gather and store oil and gas. Exploration and development costs include administrative expenses and depreciation applicable to support equipment associated with these activities. Costs incurred, summarized below, include both amounts expensed and capitalized.

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
Year 2010						
Consolidated Entities						
Property acquisition						
Proved	$ 655	$ 1	$ -	$ -	$ -	$ 656
Unproved	1,599	1,241	-	-	179	3,019
Exploration	877	20	66	-	365	1,328
Development	3,034	251	264	-	3,018	6,567
Total	$ 6,165	$ 1,513	$ 330	$ -	$ 3,562	$ 11,570
Company Share of Equity Accounted Entities						
Property acquisition						
Proved	$ -	$ -	$ -	$ -	$ -	$ -
Unproved	-	-	-	9	-	9
Exploration	-	-	-	2	-	2
Development	-	49	-	506	23	578
Total	$ -	$ 49	$ -	$ 517	$ 23	$ 589

Non-controlling interest share of total costs incurred by consolidated entities in Trinidad and Other Countries and Continents for the year ended December 31, 2010, amounted to $98 million and $1,137 million, respectively.

BP AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION
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Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
Year 2009						
Consolidated Entities						
Property acquisition						
Proved	$ -	$ -	$ -	$ -	$ 104	$ 104
Unproved	370	1	-	-	-	371
Exploration	1,377	13	71	-	174	1,635
Development	4,208	386	360	-	2,475	7,429
Total	$ 5,955	$ 400	$ 431	$ -	$ 2,753	$ 9,539
Company Share of Equity Accounted Entities						
Property acquisition						
Proved	$ -	$ -	$ -	$ -	$ -	$ -
Unproved	-	-	-	31	-	31
Exploration	-	-	-	21	-	21
Development	-	30	-	531	-	561
Total	$ -	$ 30	$ -	$ 583	$ -	$ 613

Non-controlling interest share of total costs incurred by consolidated entities in Trinidad and Other Countries and Continents for the year ended December 31, 2009, amounted to $126 million and $797 million, respectively.

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SUPPLEMENTAL INFORMATION
(UNAUDITED)

Millions of Dollars	United States	Other Countries in North America	Trinidad	Other Countries in South America	Other Countries and Continents	Total
Year 2008						
Consolidated Entities						
Property acquisition						
Proved	$ 1,382	$ 2	$ -	$ -	$ 136	$ 1,520
Unproved	2,942	-	-	-	42	2,984
Exploration	862	31	69	-	224	1,186
Development	4,842	243	624	-	2,382	8,091
Total	$ 10,028	$ 276	$ 693	$ -	$ 2,784	$ 13,781
Company Share of Equity Accounted Entities						$ 3,100

Non-controlling interest share of total costs incurred by consolidated entities in Trinidad and Other Countries and Continents for the year ended December 31, 2008 amounted to, $205 million and $541 million, respectively.