NOBLE ENERGY INC
Form 10-Q
April 29, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

T QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2010

OR

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	73-0785597
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100	
Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes T No £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer T Accelerated filer £ Non-accelerated filer £ Smaller reporting company £
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes £ No T

As of April 16, 2010, there were 174,624,653 shares of the registrant’s common stock, par value $3.33 1/3 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(in millions, except per share amounts)
(unaudited)

	Three Months Ended March 31, 2010	2009
Revenues		
Oil, Gas and NGL Sales	$688	$406
Income from Equity Method Investees	26	11
Other Revenues	19	24
Total	733	441
Costs and Expenses		
Production Expense	139	130
Exploration Expense	80	42
Depreciation, Depletion and Amortization	216	200
General and Administrative	66	59
Asset Impairments	-	437
Other Operating (Income) Expense, Net	14	(6)
Total	515	862
Operating Income (Loss)	218	(421)
Other (Income) Expense		
Gain on Commodity Derivative Instruments	(145)	(73)
Interest, Net of Amount Capitalized	20	18
Other Non-Operating Expense, Net	-	8
Total	(125)	(47)
Income (Loss) Before Income Taxes	343	(374)
Income Tax Provision (Benefit)	106	(186)
Net Income (Loss)	$237	$(188)
Earnings (Loss) Per Share, Basic	$1.36	$(1.09)
Earnings (Loss) Per Share, Diluted	1.34	(1.09)
Weighted Average Number of Shares Outstanding, Basic	174	173
Weighted Average Number of Shares Outstanding, Diluted	177	173

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

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Noble Energy, Inc.
Consolidated Balance Sheets
(in millions)

	(unaudited) March 31, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,031	$ 1,014
Accounts Receivable, Net	380	465
Other Current Assets	186	199
Total Assets, Current	1,597	1,678
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	13,443	12,584
Property, Plant and Equipment, Other	243	240
Total Property, Plant and Equipment, Gross	13,686	12,824
Accumulated Depreciation, Depletion and Amortization	(4,090)	(3,908)
Total Property, Plant and Equipment, Net	9,596	8,916
Goodwill	757	758
Other Noncurrent Assets	502	455
Total Assets	$12,452	$ 11,807
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$570	$ 548
Other Current Liabilities	435	442
Total Liabilities, Current	1,005	990
Long-Term Debt	2,366	2,037
Deferred Income Taxes, Noncurrent	2,104	2,076
Other Noncurrent Liabilities	582	547
Total Liabilities	6,057	5,650
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3; 250 Million Shares Authorized; 195 Million and 194 Million Shares Issued, Respectively	649	645
Additional Paid in Capital	2,304	2,260
Accumulated Other Comprehensive Loss	(78)	(75)
Treasury Stock, at Cost; 19 Million Shares	(627)	(615)
Retained Earnings	4,147	3,942
Total Shareholders' Equity	6,395	6,157
Total Liabilities and Shareholders' Equity	$12,452	$ 11,807

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

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Noble Energy, Inc.
Consolidated Statements of Cash Flows
(in millions)
(unaudited)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash Flows From Operating Activities		
Net Income (Loss)	$237	$(188)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	216	200
Dry Hole Expense	39	2
Asset Impairments	-	437
Deferred Income Taxes	27	(301)
Income from Equity Method Investees	(26)	(11)
Dividends from Equity Method Investees	13	-
Unrealized (Gain) Loss on Commodity Derivative Instruments	(147)	80
Other Adjustments for Noncash Items Included in Income	21	(18)
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	85	(34)
(Increase) Decrease in Other Current Assets	50	(1)
Increase (Decrease) in Accounts Payable	27	(35)
Increase in Other Current Liabilities	33	56
Other Operating Assets and Liabilities, Net	13	(2)
Net Cash Provided by Operating Activities	588	185
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(383)	(399)
DJ Basin Asset Acquisition	(466)	-
Net Cash Used in Investing Activities	(849)	(399)
Cash Flows From Financing Activities		
Exercise of Stock Options	21	11
Excess Tax Benefits from Stock-Based Awards	13	3
Dividends Paid, Common Stock	(32)	(31)
Purchase of Treasury Stock	(12)	(1)
Proceeds from Credit Facilities	610	180
Repayment of Credit Facilities	(322)	(1,060)
Proceeds from Issuance of Senior Long-Term Debt	-	989
Net Cash Provided by Financing Activities	278	91
Increase (Decrease) in Cash and Cash Equivalents	17	(123)
Cash and Cash Equivalents at Beginning of Period	1,014	1,140
Cash and Cash Equivalents at End of Period	$1,031	$1,017

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

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Noble Energy, Inc.
Consolidated Statements of Shareholders' Equity
(in millions)
(unaudited)

	Common Stock	Additional Paid in Capital	Acumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholder's Equity
December 31, 2009	$645	$2,260	$ (75)	$(615)	$3,942	$ 6,157
Net Income	-	-	-	-	237	237
Stock-based Compensation Expense	-	14	-	-	-	14
Exercise of Stock Options	2	19	-	-	-	21
Tax Benefits Related to Exercise of Stock Options	-	13	-	-	-	13
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (18 cents per share)	-	-	-	-	(32)	(32)
Changes in Treasury Stock, Net	-	-	-	(12)	-	(12)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	4	-	-	4
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	(7)	-	-	(7)
March 31, 2010	$649	$2,304	$ (78)	$(627)	$4,147	$ 6,395
December 31, 2008	$641	$2,193	$ (110)	$(614)	$4,199	$ 6,309
Net Loss	-	-	-	-	(188)	(188)
Stock-based Compensation Expense	-	12	-	-	-	12
Exercise of Stock Options	2	9	-	-	-	11
Tax Benefits Related to Exercise of Stock Options	-	3	-	-	-	3
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (18 cents per share)	-	-	-	-	(31)	(31)
Changes in Treasury Stock, Net	-	-	-	(1)	-	(1)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	11	-	-	11
Net Change in Other	-	-	(1)	-	-	(1)
March 31, 2009	$645	$2,215	$ (100)	$(615)	$3,980	$ 6,125

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 1. Organization and Nature of Operations
Noble Energy, Inc. (Noble Energy, we or us) is an independent energy company engaged in worldwide crude oil, natural gas and NGL exploration and production. We operate primarily in the Rocky Mountains, Mid-Continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel and West Africa.

Note 2. Basis of Presentation
Presentation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US generally accepted accounting principles (GAAP) for complete financial statements. The accompanying consolidated financial statements at March 31, 2010 and December 31, 2009 and for the three months ended March 31, 2010 and 2009 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the three-month period ended March 31, 2010 are not necessarily indicative of the results that may be expected for the year ended December 31, 2010. Certain reclassifications of amounts previously reported have been made to conform to current year presentations. These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2009.

Estimates The preparation of consolidated financial statements in conformity with GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates.

Statements of Operations Information Other statements of operations information is as follows:

	Three Months Ended March 31,	
	2010	2009
(millions)		
Other Revenues		
Electricity Sales (1)	$19	$20
Other	-	4
Total	$19	$24
Production Expense		
Lease Operating Expense	$88	$100
Production and Ad Valorem Taxes	34	18
Transportation Expense	17	12
Total	$139	$130
Other Operating Expense, Net		
Electricity Generation Expense (1)	$10	$(30)
Other, Net	4	24
Total	$14	$(6)
Other Non-Operating (Income) Expense, Net		
Deferred Compensation (2)	$2	$5
Interest Income	(1)	-

Other (Income) Expense, Net	(1)	3
Total	$-	$8

(1) Includes amounts related to our 100%-owned Ecuador integrated power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation, depletion and amortization expense (DD&A) and changes in the allowance for doubtful accounts. Electricity generation expense for first quarter 2009 includes a reduction in the allowance for doubtful accounts of $46 million received in accordance with the terms of a settlement with entities purchasing electricity in Ecuador.

(2) Amount represents increases in the fair value of our common stock held in a rabbi trust.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	March 31, 2010	December 31, 2009
Accounts Receivable, Net		
Commodity Sales	$181	$ 205
Joint Interest Billings	177	140
Refund of Deepwater Gulf of Mexico Royalties (1)	12	97
Other	41	54
Allowance for Doubtful Accounts (2)	(31)	(31)
Total	$380	$ 465
Other Current Assets		
Inventories, Current	$90	$ 89
Commodity Derivative Assets, Current	50	13
Prepaid Expenses and Other Assets, Current	12	65
Deferred Income Taxes, Net, Current	34	32
Total	$186	$ 199
Other Noncurrent Assets		
Equity Method Investments	$316	$ 303
Mutual Fund Investments	110	108
Commodity Derivative Assets, Noncurrent	29	1
Other Assets, Noncurrent	47	43
Total	$502	$ 455
Accounts Payable - Trade		
Capital Costs	$270	$ 277
Royalties Payable	66	65
Marketing and Trading Activities	27	76
Lease Operating Expense	31	27
Other	176	103
Total	$570	$ 548
Other Current Liabilities		
Production and Ad Valorem Taxes	$132	$ 103
Commodity Derivative Liabilities, Current	22	100
Interest Rate Derivative Liability, Current	11	-
Income Taxes Payable	119	60
Asset Retirement Obligations, Current	51	51
Interest Payable	24	37
Other	76	91
Total	$435	$ 442
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$219	$ 213
Asset Retirement Obligations, Noncurrent	199	181
Accrued Benefit Costs, Noncurrent	79	76
Commodity Derivative Liabilities, Noncurrent	7	17

Other	78	60
Total	$582	$ 547

(1) In March 2010, we received a refund of $84 million attributable to royalties that we previously paid on crude oil and natural gas produced in the deepwater Gulf of Mexico from January 1, 2003 through July 31, 2009. The amount remaining at March 31, 2010 represents accrued interest which we expect to receive within 12 months.

(2) See footnote (1) to Statements of Operations Information table above.

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Noble Energy, Inc.
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(unaudited)

Subsequent Events   In April 2010, we determined that the Double Mountain exploration well (30% non-operated working interest) in the deepwater Gulf of Mexico had found noncommercial quantities of hydrocarbons and will be plugged and abandoned. As a result, we recorded $38 million (pre-tax) of additional dry hole expense for the three months ended March 31, 2010.

Recently Adopted Accounting Standards   In February 2010, the Financial Accounting Standards Board (FASB) amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance effective first quarter 2010.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance effective first quarter 2010. Adoption had no impact on our financial position or results of operations. See Note 6. Fair Value Measurements and Disclosures.

Note 3. DJ Basin Asset Acquisition

On March 1, 2010, we acquired substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. The acquisition included properties located in the Greater Denver-Julesberg (DJ) Basin, one of our core onshore US operating areas. We funded the acquisition using our existing credit facility.

We acquired the assets for $466 million cash and assumed net liabilities totaling $43 million, for a total purchase price of $509 million.

The total purchase price was allocated preliminarily to the assets acquired and the liabilities assumed based on fair values at the acquisition date. The preliminary allocation was as follows:

- $363 million to proved oil and gas properties; and
- $146 million to unproved oil and gas properties.

The difference between the total purchase price and the fair values of the assets acquired as of March 1, 2010 was de minimis.

To estimate the fair values of the properties, we used an income approach as comparable market data was not available. We utilized a discounted cash flow model which took into account the following inputs to arrive at estimates of future net cash flows:

- estimated quantities of crude oil and natural gas prepared by our qualified petroleum engineers;
- estimated future commodity prices based on NYMEX crude oil and natural gas futures prices as of the acquisition date and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar DJ basin properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar DJ basin properties which we operate.

To estimate the fair value of proved properties, we discounted the future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. To compensate for the inherent risk of estimating and valuing unproved properties, we reduced the discounted future net cash flows of probable and possible reserves by additional risk-weighting factors. The fair values of the proved and unproved oil and gas properties are considered Level 3 fair value measurements.

Certain data necessary to complete the final purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed. We expect to complete the final purchase price allocation during the 12-month period following the acquisition date, during which time the preliminary allocation may be revised.

Related transaction costs were expensed. We have not presented pro forma information for the acquired business as the impact of the acquisition was not material to our consolidated balance sheet as of March 31, 2010, or our consolidated results of operations for the three months ended March 31, 2010.

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(unaudited)

Note 4. Debt

Our debt consists of the following:

	March 31, 2010		December 31, 2009	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Credit Facility (1)	$ 670	0.55 %	$ 382	0.54 %
5¼% Senior Notes, due April 15, 2014	200	5.25 %	200	5.25 %
8¼% Senior Notes, due March 1, 2019	1,000	8.25 %	1,000	8.25 %
7¼% Notes, due October 15, 2023	100	7.25 %	100	7.25 %
8% Senior Notes, due April 1, 2027	250	8.00 %	250	8.00 %
7¼% Senior Debentures, due August 1, 2097	84	7.25 %	84	7.25 %
Obligation Under FPSO Lease (2)	69	-	29	-
Total	2,373		2,045	
Unamortized Discount	(7)		(8)	
Total Debt, Net of Discount	$ 2,366		$ 2,037	

(1) The increase in the credit facility balance from December 31, 2009 represents amounts drawn to fund the DJ Basin asset acquisition. See Note 3. DJ Basin Asset Acquisition.

(2) Amount reported is based on percentage of FPSO construction activities completed as of March 31, 2010, and therefore does not reflect future minimum lease obligations. The increase in the FPSO lease obligation is a non-cash financing activity.

Note 5. Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments In order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, collars and basis swaps. While these instruments mitigate the cash flow risk of future reductions in commodity prices they may also curtail benefits from future increases in commodity prices.

We may also use derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. We may designate these as cash flow hedges.

All derivative instruments are reflected as either assets or liabilities at fair value in our consolidated balance sheets. See Note 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of derivative instruments and gross amounts of derivative assets and liabilities.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of financial institutions. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices as well as incur a loss. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments in an asset position.

Accounting for Commodity Derivative Instruments We recognize all gains and losses on commodity derivative instruments in earnings during the period in which they occur. Prior to January 1, 2008, we elected to designate certain of our commodity derivative instruments as cash flow hedges. Net derivative gains and losses that were deferred in accumulated other comprehensive loss (AOCL) as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur. See Derivative Instruments in Cash Flow Hedging Relationships table below.

Accounting for Interest Rate Derivative Instruments Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. In January 2010, in anticipation of a long-term debt issuance, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on the anticipated debt issuance. We are accounting for the instrument as a cash flow hedge against the variability of interest payments attributable to changes in interest rates on the forecasted issuance of fixed-rate debt. The swap is in the notional amount of $500 million and is based on a 30-year LIBOR swap rate.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Unsettled Derivative Instruments As of March 31, 2010, we had entered into the following crude oil derivative instruments:

	Variable to Fixed Price Swaps			Two Way Collars			
Production Period	Index	Bbls Per Day	Weighted Average Fixed Price	Index	Bbls Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2nd Qtr - 4th Qtr 2010	NYMEX WTI	3,000	$ 83.36	NYMEX WTI	14,500	$ 61.48	$ 75.63
2nd Qtr - 4th Qtr 2010	Dated Brent	1,000	80.05	Dated Brent	7,000	64.00	73.96
2010 Average		4,000	82.53		21,500	62.30	75.09
2011	-	-	-	NYMEX WTI	8,000	80.25	88.74

		Three Way Collars (1)			
Production Period	Index	Bbls Per Day	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2011	NYMEX WTI	4,000	$ 55.00	$ 75.00	$ 101.78

(1) A three-way collar consists of a collar contract combined with a put option contract sold by us with a price below the floor price of the collar.

Between April 1, 2010 and April 23, 2010, we entered into additional NYMEX WTI swaps covering 5,000 Bbls per day for calendar year 2012 with a weighted average fixed price of $91.84. We also entered into an additional three way collar covering 1,000 Bbls per day for calendar year 2011 with short put, floor and ceiling prices of $60.00, $80.00 and $100.20, respectively.

As of March 31, 2010, we had entered into the following natural gas derivative instruments:

	Variable to Fixed Price Swaps			Two Way Collars			
Production Period	Index	MMBtu Per Day	Weighted Average Fixed Price	Index	MMBtu Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2nd Qtr - 4th Qtr 2010	NYMEX HH	40,000	$ 6.10	NYMEX HH (1)	210,000	$ 5.90	$ 6.73

2nd Qtr - 4th Qtr 2010	-	-	-	IFERC CIG (2)	15,000	6.25	8.10
2010 Average		40,000	6.10		225,000	5.93	6.82
2011	NYMEX HH	25,000	6.41	NYMEX HH	140,000	5.95	6.82

(1) Henry Hub
(2) Colorado Interstate Gas - Northern System

Between April 1, 2010 and April 23, 2010, we entered into NYMEX HH three way collars covering 50,000 MMBtu per day for calendar year 2011 with weighted average short put, floor and ceiling prices of $4.00, $5.00 and $6.70, respectively. We also entered into additional NYMEX HH three way collars covering 50,000 MMBtu per day for calendar year 2012 with weighted average short put, floor and ceiling prices of $4.75, $5.50 and $7.92, respectively.

As of March 31, 2010, we had entered into the following natural gas basis swaps:

		Basis Swaps		
Production Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2nd Qtr - 4th Qtr 2010	IFERC CIG	NYMEX HH	110,000	$ (1.49)
2011	IFERC CIG	NYMEX HH	120,000	(0.73)

Between April 1, 2010 and April 23, 2010, we did not enter into any additional natural gas basis swaps.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Fair Value Amounts and Gains and Losses on Derivative Instruments   The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2010		December 31, 2009		March 31, 2010		December 31, 2009	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 50	Current Assets	$ 13	Current Liabilities	$ 22	Current Liabilities	$ 100
	Noncurrent Assets	29	Noncurrent Assets	1	Noncurrent Liabilities	7	Noncurrent Liabilities	17
Interest Rate Derivative Instruments (Designated as Hedging Instruments)	Current Assets	-	Current Assets	-	Current Liabilities	11	Current Liabilities	-
Total		$ 79		$ 14		$ 40		$ 117

The effect of derivative instruments on our consolidated statements of operations was as follows:

Commodity Derivative Instruments Not Designated as Hedging Instruments

Amount of (Gain) Loss on Derivative Instruments Recognized in Income

	Three Months Ended March 31,	
(millions)	2010	2009
Realized Mark-to-Market (Gain) Loss	$ 2	$ (153)
Unrealized Mark-to-Market (Gain) Loss	(147)	80
Total (Gain) Loss on Commodity Derivative Instruments	$ (145)	$ (73)

Derivative Instruments in Cash Flow Hedging Relationships

	Amount of (Gain) Loss on Derivative Instruments Recognized in Other Comprehensive (Income) Loss		Amount of (Gain) Loss on Derivative Instruments Reclassified from Accumulated Other Comprehensive Loss	
	Three Months Ended March 31,			
	2010	2009	2010	2009
(millions)				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$ -	$ -	$ 5	$ 17
Natural Gas Derivative Instruments	-	-	1	-
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	11	-	-	-
Total	$ 11	-	$ 6	$ 17

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. Net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur.

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

AOCL   As of March 31, 2010, the balance in AOCL included deferred losses of $9 million related to the fair value of commodity derivative instruments previously accounted for as cash flow hedges. The deferred losses are net of deferred income tax benefits of $5 million. All remaining deferred losses will be reclassified to earnings during the period April 1 through December 31, 2010, as the forecasted transactions occur, and will be recorded as a reduction in oil and gas sales of approximately $14 million before tax.

AOCL also included a deferred loss of $9 million, net of tax, related to interest rate derivative instruments. Of this amount, $2 million, net of tax, is currently being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014. Approximately $7 million will remain in AOCL until fixed-rate debt is issued, at which time we will begin amortizing it to interest expense over the life of the related debt issuance.

Note 6. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable   The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments   Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments   Our commodity derivative instruments consist of variable to fixed price commodity swaps, collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves for the underlying commodities as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Derivative Instrument   We estimate the fair value of our forward starting swap based on published interest rate yield curves as of the date of the estimate. The fair values of interest rate derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of interest rate derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates.

Deferred Compensation Liability   A portion of our deferred compensation liability is measured at fair value, which is dependant upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See Mutual Fund Investments above.

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Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

(millions)	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
March 31, 2010					
Financial Assets					
Mutual Fund Investments	$110	$-	$ -	$-	$ 110
Commodity Derivative Instruments	-	184	-	(105)	79
Financial Liabilities					
Commodity Derivative Instruments	-	(134)	-	105	(29)
Interest Rate Derivative Instrument	-	(11)	-	-	(11)
Portion of Deferred Compensation Liability Measured at Fair Value	(172)	-	-	-	(172)
December 31, 2009					
Financial Assets					
Mutual Fund Investments	$108	$-	$ -	$-	$ 108
Commodity Derivative Instruments	-	42	-	(28)	14
Financial Liabilities					
Commodity Derivative Instruments	-	(145)	-	28	(117)
Portion of Deferred Compensation Liability Measured at Fair Value	(168)	-	-	-	(168)

(1) Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

(2) Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.

(3) Level 3 measurements are fair value measurements which use unobservable inputs.

(4) Amount represents the impact of master netting agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Asset Acquisition   See Note 3. DJ Basin Asset Acquisition.

Asset Impairments (First Quarter 2009)   We determined that the carrying amount of Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, was not recoverable from future cash flows and, therefore, was impaired at March 31, 2009. We also impaired our Gulf of Mexico Main Pass asset which had been reclassified from held-for-sale to held-and-used. The impaired assets, which had a total carrying amount of $753 million, were reduced to their estimated fair value of $316 million, resulting in total pre-tax (non-cash) impairments of $437 million.

The fair values of the properties were determined using a discounted cash flow method, as comparable market data was not available. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. The asset impairments were Level 3 fair value measurements.

Additional Fair Value Disclosures

Debt   The fair value of fixed-rate debt is estimated based on the published market prices for the same or similar issues. The fair value of floating-rate debt is estimated using the carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 4. Debt.

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Fair value information regarding our debt is as follows:

(millions)	March 31, 2010 Carrying Amount	March 31, 2010 Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Long-Term Debt, Net of Unamortized Discount (1)	$ 2,297	$ 2,571	$ 2,008	$ 2,279

(1) Excludes obligation under FPSO lease.

Note 7. Capitalized Exploratory Well Costs

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

(millions)	Three Months Ended March 31, 2010
Capitalized Exploratory Well Costs, Beginning of Period	$ 432
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	32
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(6)
Capitalized Exploratory Well Costs Charged to Expense	(2)
Capitalized Exploratory Well Costs, End of Period	$ 456

The following table provides an aging of capitalized exploratory well costs (suspended 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)	March 31, 2010	December 31, 2009
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 97	$ 158
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	359	274
Balance at End of Period	$ 456	$ 432
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	9	5

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling as of March 31, 2010:

		Suspended Since	
	Total	2009	2008

(millions) Project				2007 & Prior
Blocks O and I (West Africa)	$ 194	$ 13	$ 71	$ 110
Tamar and Dalit (Israel)	58	33	24	1
Gunflint (Deepwater Gulf of Mexico)	49	-	49	-
Redrock (Deepwater Gulf of Mexico)	17	-	-	17
Flyndre (North Sea)	15	-	-	15
Selkirk (North Sea)	20	-	-	20
Other	6	6	-	-
Total Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	$ 359	$ 52	$ 144	$ 163

West Africa   The West Africa project includes Blocks O and I offshore Equatorial Guinea and the YoYo concession and Tilapia production sharing contract offshore Cameroon. We have evaluated the potential for additional liquids and gas projects, and determined that the next development after Aseng will be at the Belinda field. We are also evaluating future oil projects at Diega and Carmen. In Cameroon, we will acquire a 3-D seismic survey over YoYo and portions of Tilapia during 2010, and exploration drilling is currently planned in Tilapia.

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Israel   The Israel project includes the Tamar and Dalit prospects, both significant 2009 natural gas discoveries located offshore Israel. We are moving forward with Tamar development plans, and expect project sanction and recording of proved reserves in 2010, with first production projected for 2012. We have also signed letters of intent to sell natural gas from the Tamar field. In addition to the remaining exploratory well costs that have been capitalized for a period greater than one year, we have incurred $39 million in suspended costs related to additional drilling activity in Israel through March 31, 2010.

Gunflint (Deepwater Gulf of Mexico)   Gunflint (Mississippi Canyon Block 948) is our largest deepwater Gulf of Mexico discovery to date. We are currently acquiring additional seismic information and preparing to drill an appraisal well.

Redrock (Deepwater Gulf of Mexico)   Redrock (Mississippi Canyon Block 204) was a 2006 natural gas/condensate discovery and is currently considered a co-development candidate with Raton South (Mississippi Canyon Block 292). The anticipated development plan consists of tying Raton South back through the Gemini system to a host platform at Viosca Knoll Block 900 for processing and then connecting Redrock into this gathering system. Tie-back of Redrock is anticipated to occur following the development of Raton South.

Flyndre (North Sea)   The Flyndre project is located in the UK sector of the North Sea and we successfully completed an exploratory appraisal well in 2007. We are currently working with the project operator and other partners to finalize the field development plan and relevant operating agreements.

Selkirk (North Sea)   The Selkirk project is also located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

Other   Other projects consist of three onshore US wells which continue to be evaluated by various means including additional seismic work, drilling additional wells and evaluating the potential of the exploration well.

Note 8. Asset Retirement Obligations
Asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Three Months Ended March 31,	
	2010	2009
(in millions)		
Asset Retirement Obligations, Beginning of Period	$ 232	$ 211
Liabilities Incurred in Current Period	14	1
Liabilities Settled in Current Period	(4)	(2)
Revisions	4	16
Accretion Expense	4	3
Asset Retirement Obligations, End of Period	$ 250	$ 229

Liabilities incurred in 2010 were due to the DJ Basin asset acquisition. Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 9. Employee Benefit Plans

We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. Net periodic benefit cost related to the retirement and restoration plans was as follows:

	Three Months Ended March 31,	
	2010	2009
(millions)		
Service Cost	$ 4	$ 3
Interest Cost	3	3
Expected Return on Plan Assets	(3)	(3)
Other	1	1
Net Periodic Benefit Cost	$ 5	$ 4

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During the three months ended March 31, 2010, we made cash contributions of $2 million to the pension plan.

Note 10. Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended March 31,	
	2010	2009
(millions)		
Stock-Based Compensation Expense	$ 14	$ 12
Tax Benefit Recognized	(5)	(4)

During the three months ended March 31, 2010, we granted one million stock options with a weighted average grant-date fair value of $25.06 per share and awarded 0.4 million shares of restricted stock subject to service conditions with a weighted average grant-date fair value of $75.10 per share.

Note 11. Basic and Diluted Earnings (Loss) Per Share

Basic earnings (loss) per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock may include the effect of our shares held in a rabbi trust, outstanding stock options or shares of restricted stock, except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings (loss) per share:

	Three Months Ended March 31,	
	2010	2009
(millions, except per share amounts)		
Net Income (Loss)	$ 237	$ (188)
Weighted Average Number of Shares Outstanding, Basic	174	173
Incremental Shares from Assumed Conversion of Dilutive Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	3	-
Weighted Average Number of Shares Outstanding, Diluted	177	173
Earnings (Loss) Per Share, Basic	$ 1.36	$ (1.09)
Earnings (Loss) Per Share, Diluted	1.34	(1.09)

Stock options, restricted shares and common shares held in a rabbi trust that were antidilutive for first quarter 2010 and 2009, and therefore excluded from the calculation of diluted earnings (loss) per share, totaled 1.2 million and 4.6 million, respectively.

The effect of stock options and unvested shares of restricted stock outstanding has not been included in the calculation of weighted average shares outstanding for diluted earnings per share for the three months ending March 31, 2009 as their effect would have been antidilutive. Had we recognized net income for this period, incremental shares attributable to the assumed exercise of outstanding options and shares of restricted stock would have increased diluted weighted average shares outstanding by 1.6 million shares for the three months ended March 31, 2009.

Note 12. Income Taxes

The income tax provision (benefit) consists of the following:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
(millions)		
Current	$ 79	$ 115
Deferred	27	(301)
Total Income Tax Provision (Benefit)	$ 106	$ (186)

Our effective tax rate decreased to 31% for the first three months of 2010 as compared with 50% for the first three months of 2009. For the first quarter of 2010, the effective rate is lower than the federal statutory rate because our income from equity method investees results in a favorable permanent difference, which has the impact of decreasing the statutory rate when our pre-tax income is positive.

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The 2009 rate was the result of a tax benefit divided by a pre-tax loss. In the case of a loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate. The deferred tax benefit for the three months ended March 31, 2009 was due primarily to the realization in 2009 of a significant amount of unrealized mark-to-market gain originally recorded in 2008, resulting in the reversal of most of the associated deferred tax liability recorded in 2008. In addition, we recorded a deferred tax asset with respect to impairment losses on our US oil and gas properties.

During first quarter 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense by $13 million of which $9 million was recorded in 2008. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

Unrecognized Tax Positions We do not have significant unrecognized tax benefits as of March 31, 2010. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. We did not accrue interest or penalties at March 31, 2010, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax, and we believe that we are below the minimum statutory threshold for imposition of penalties.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, China – 2006, Israel – 2008, UK – 2007 and the Netherlands – 2005.

Note 13. Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and certain items recorded directly to shareholders' equity and classified as AOCL. Comprehensive income (loss) was calculated as follows:

	Three Months Ended March 31,	
	2010	2009
(millions)		
Net Income (Loss)	$ 237	$ (188)
Other Items of Comprehensive Income (Loss)		
Oil and Gas Cash Flow Hedges		
Realized Losses Reclassified Into Earnings	6	17
Less Tax Provision	(2)	(6)
Interest Rate Cash Flow Hedges		
Unrealized Change in Fair Value	(11)	-
Less Tax Provision	4	-
Net Change in Other	-	(1)
Other Comprehensive Income (Loss)	(3)	10
Comprehensive Income (Loss)	$ 234	$ (178)

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Note 14. Segment Information
We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration and production: the United States; West Africa (Equatorial Guinea and Cameroon); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. The following data was prepared on the same basis as our consolidated financial statements and excludes the effects of income taxes.

(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate (1)
Three Months Ended March 31, 2010						
Revenues from Third Parties	$ 713	$ 510	$ 61	$ 33	$ 66	$ 43
Reclassification from AOCL (2)	(6)	(6)	-	-	-	-
Income from Equity Method Investees	26	-	26	-	-	-
Total Revenues	733	504	87	33	66	43
DD&A	216	181	8	4	15	8
Gain on Commodity Derivative Instruments	(145)	(145)	-	-	-	-
Income (Loss) Before Income Taxes	343	289	66	26	36	(74)
Three Months Ended March 31, 2009						
Revenues from Third Parties	$ 447	$ 289	$ 58	$ 28	$ 34	$ 38
Reclassification from AOCL (2)	(17)	(9)	(8)	-	-	-
Income from Equity Method Investees	11	-	11	-	-	-
Total Revenues	441	280	61	28	34	38
DD&A	200	169	9	5	9	8
Asset Impairments	437	437	-	-	-	-
Gain on Commodity Derivative Instruments	(73)	(67)	(6)	-	-	-
Income (Loss) Before Income Taxes	(374)	(409)	42	21	11	(39)
Total Assets at March 31, 2010 (3)	12,452	9,228	1,795	533	671	225
Total Assets at December 31, 2009 (3)	11,807	8,669	1,731	486	635	286

(1) Other international includes operations in China and Ecuador.

(2) Revenues include decreases resulting from hedging activities. The decreases resulted from hedge gains and losses that were deferred in AOCL, as a result of previous cash flow hedge accounting, and subsequently reclassified to revenues.

(3) The US reporting unit includes goodwill of $757 million at March 31, 2010 and $758 million at December 31, 2009.

Note 15. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

EXECUTIVE OVERVIEW

We are an independent energy company engaged in worldwide crude oil, natural gas and NGL exploration and production. Our strategy is to achieve growth in earnings and cash flows through the continued expansion of a high quality portfolio of producing assets that is diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

Our financial results for first quarter 2010 included:

- net income of $237 million, as compared with a net loss of $188 million for first quarter 2009;
- gain on commodity derivative instruments of $145 million (including unrealized mark-to-market gain of $147 million) as compared with a gain on commodity derivative instruments of $73 million (including unrealized mark-to-market loss of $80 million) for first quarter 2009;
- diluted earnings per share of $1.34, as compared with diluted loss per share of $1.09 for first quarter 2009;
- cash flow provided by operating activities of $588 million, as compared with $185 million for first quarter 2009;
- collection of $84 million refund of deepwater Gulf of Mexico royalties;
- capital spending (excluding impact of the DJ Basin asset acquisition and FPSO accrual) of $409 million as compared with $386 million in 2009;
- net increase of $328 million principal amount of debt, including FPSO accrual;
- ending cash and cash equivalents balance of $1 billion, unchanged from December 31, 2009;
- total liquidity of $2.5 billion at March 31, 2010, consisting of ending cash balance plus funds available under credit facility, as compared with $2.7 billion at December 31, 2009; and
- ratio of debt-to-book capital of 27% as compared with 25% at December 31, 2009.

Significant operational highlights for first quarter 2010 included:

United States Onshore
- record legacy Wattenberg field and onshore US sales volumes;
- DJ Basin asset acquisition which enhanced our largest onshore US property at the Wattenberg field; and
- expansion of our central DJ Basin position to over 730,000 net acres.

United States Offshore
- apparent high bidder on 16 deepwater lease blocks in the Central Gulf of Mexico lease sale 213.

International
- initiation of field development drilling at the Aseng oil project offshore Equatorial Guinea; and
- acquisition of 3-D seismic in the Eastern Mediterranean.

DJ Basin Asset Acquisition   On March 1, 2010, we closed the acquisition of substantially all of the US Rockies upstream assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. The transaction increases our presence in the Wattenberg field and further expands our opportunity in the DJ Basin. The acquisition added approximately 10 MBoepd to our daily production base and approximately 50 MMBoe of proved reserves. A majority of the reserves are within the Wattenberg field, where our largest onshore US asset is located.

Exploration Program Continued investment in significant exploration remains a key component to our strategy. During first quarter 2010, we continued to build upon our attractive exploration inventory in the deepwater Gulf of Mexico by participating in the Central Gulf of Mexico Lease Sale 213. We were the apparent high bidder on 16 deepwater lease blocks which cover in excess of 82,500 net acres in water depths up to 7,800 feet. Should all of the bids be awarded, our total acreage position in the deepwater Gulf of Mexico will expand to over 472,500 net acres. All high bids are subject to approval by the Minerals Management Service of the US Department of the Interior.

We also are processing 3-D seismic data recently acquired for the Eastern Mediterranean region, shooting 3-D seismic in Cameroon, and drilling the Deep Blue test well in the deepwater Gulf of Mexico. In April 2010, we announced that the Double Mountain exploration well (30% non-operated working interest) in the deepwater Gulf of Mexico had found noncommercial quantities of hydrocarbons and will be plugged and abandoned.

Major Development Projects During first quarter 2010, we moved forward on several of our major development projects. Offshore Equatorial Guinea, we initiated development drilling at the Aseng oil field, delivered the FPSO vessel that will be used in the development of the Aseng field to the shipyard in late March for conversion, and continued FEED (front end engineering design) work for the Belinda project. Offshore Israel, we are in the process of finalizing a development plan for the Tamar field.

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Production Volumes On a BOE basis, production was lower first quarter 2010 as compared with first quarter 2009. In Israel, there was a decrease in demand for natural gas to produce electricity for heating, and a higher percentage of the demand was met by imports from Egypt. As expected, crude oil and natural gas sales volumes in Equatorial Guinea for first quarter 2010 were lower due to the planned shut-in of the Alba field for scheduled facility maintenance and repair. These decreases were offset by an increase in crude oil and NGL sales volumes due to record production in Wattenberg and other onshore US areas as well as facility enhancements and a new well in the North Sea.

Commodity Price Changes and Hedging We experienced a significant improvement in average realized commodity prices over first quarter 2009. However, commodity prices remain uncertain and we have expanded our hedging program with the addition of three-way collars. A three-way collar consists of a collar contract combined with a put option contract sold by us with a price below the floor price of the collar. We have hedged approximately 40% of our expected world-wide crude oil production and 68% of our expected domestic natural gas production for the remainder of 2010.

OUTLOOK

Our expected crude oil, natural gas and NGL production for the remainder of 2010 may be impacted by several factors including:

- overall level and timing of capital expenditures which, dependent upon our drilling success and notwithstanding the other factors listed below, are expected to maintain our near-term production volumes (See 2010 Budget discussion below);
- impact of DJ Basin asset acquisition, which we expect to add approximately 10 MBoepd or 46 MMcf of natural gas and 2.5 MBbls of liquids to our daily production base for the remainder of 2010;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and in the North Sea;
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth and competing deliveries of natural gas from Egypt;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- potential volume curtailments in Ecuador due to unsettled economic and political environment;
- impact of asset purchases;
- timing of significant project completion and initial production; and
- impact of sales of non-core operating assets.

2010 Budget Our total capital investment program for 2010 is estimated at $2.5 billion, with 40% going toward major project investments, 20% for exploration and appraisal activities, and the remaining 40% for ongoing maintenance and near-term development opportunities. Approximately 55% of the total is to be spent in the US with the other 45% allocated to international activities.

Major project investments are expected to be about $1 billion, with the majority of capital directed toward the development of Galapagos in the deepwater Gulf of Mexico, Aseng offshore Equatorial Guinea, and Tamar offshore Israel. Approximately $500 million is slated for exploration activities, representing our largest ever annual exploration program. This program includes participation in seven high-impact offshore wells in the deepwater Gulf of Mexico, Equatorial Guinea and the Mediterranean Sea. The remainder of our budget is focused on liquid-rich and emerging opportunities onshore in the US, as well as near-term development projects in Israel, the North Sea and China.

Excluded from the capital budget discussed above is $509 million total purchase price for DJ Basin assets acquired on March 1, 2010, as well as $235 million of non-cash capital expected to be accrued for the Aseng FPSO capital lease.

We expect that the 2010 budget will be funded primarily from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing. We will evaluate the level of capital spending throughout the year based on drilling results, commodity prices, cash flows from operations and property acquisitions and divestitures. Our capital spending is integrated with our goal of maintaining a strong balance sheet and ample liquidity. See Liquidity and Capital Resources - Capital Structure/Financing Strategy, below.

Change in Insurance Coverage We are a member in Oil Insurance Limited (OIL). OIL is a mutual insurance company which insures property, pollution liability, control of well and other catastrophic risks. Due to recent reductions in windstorm coverage by OIL, we now believe it is commercially more reasonable to self insure. In April 2010, we notified OIL that we would elect to self insure our 2010 windstorm exposure. Although our recent asset retirement efforts at Main Pass on the Gulf of Mexico shelf have reduced our risk of windstorm damage, we are now responsible for substantially all windstorm-related damages.

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RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

(millions)	Three Months Ended March 31, 2010	2009	Increase (Decrease) from Prior Year
Revenues			
Oil, Gas and NGL Sales	$ 688	$ 406	69 %
Income from Equity Method Investees	26	11	136 %
Other Revenues	19	24	(21 %)
Total	$ 733	$ 441	66 %

Changes in revenues are discussed below.

Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBpd)	Natural Gas (MMcfpd)	NGLs (MBpd)	Total (Boepd) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2010							
United States (2)	40	384	13	116	$ 73.80	$ 5.46	$ 44.98
Equatorial Guinea (3) (4)	8	194	-	41	73.34	0.27	-
Israel	-	87	-	15	-	4.20	-
North Sea	9	7	-	10	77.06	5.42	-
Ecuador (5)	-	30	-	5	-	-	-
China	4	-	-	4	72.34	-	-
Total Consolidated Operations	61	702	13	191	74.12	3.79	44.98
Equity Investees (6)	2	-	4	6	75.61	-	57.99
Total Operations	63	702	17	197	$ 74.16	$ 3.79	$ 48.00
Three Months Ended March 31, 2009							
United States (2)	35	411	9	113	$ 35.65	$ 3.93	$ 24.74
	13	243	-	53	39.41	0.27	-

Equatorial Guinea (3) (4)							
Israel	-	112	-	19	-	2.81	-
North Sea	7	5	-	8	45.91	8.17	-
Ecuador (5)	-	30	-	5	-	-	-
China	4	-	-	4	36.89	-	-
Total Consolidated Operations	59	801	9	202	37.81	2.64	24.74
Equity Investees (6)	2	-	7	8	41.76	-	26.89
Total Operations	61	801	16	210	$ 37.91	$ 2.64	$ 25.62

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(2) Average realized crude oil and condensate prices reflect reductions of $1.32 per Bbl and $2.70 per Bbl for first quarter 2010 and 2009, respectively, from hedging activities. Average realized natural gas prices reflect reductions of $0.03 per Mcf and $0.01 per Mcf for first quarter 2010 and 2009, respectively, from hedging activities. The price reductions resulted from hedge losses that were previously deferred in AOCL.

(3) Average realized crude oil and condensate prices reflect a reduction of $7.08 per Bbl for first quarter 2009 from hedging activities. The price reduction resulted from hedge losses that were previously deferred in AOCL. All hedge gains or losses relating to West Africa production had been reclassified to revenues by December 31, 2009.

(4) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(5) The natural gas-to-power project in Ecuador is 100% owned by our subsidiaries and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales are included in other revenues. See Item 1. Financial Statements – Note 2. Basis of Presentation.

(6) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. See Equity Method Investees below.

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If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)			
	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas
	2010		2009	
	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)
Three Months Ended March 31,				
United States	$ (0.52)	$ 0.02	$ 21.13	$ 1.58
Equatorial Guinea	(1.73)	-	24.80	-
Total Consolidated Operations	(0.58)	0.02	17.84	0.84
Total Operations	(0.56)	0.02	17.41	0.84

An analysis of revenues from sales of crude oil, natural gas and NGLs is as follows:

(millions)	Crude Oil and Condensate	Natural Gas	NGLs	Total
Sales Revenues, First Three Months of 2009	$ 202	$ 183	$ 21	$ 406
Changes due to				
Increase (Decrease) in Sales Volumes	6	(16)	7	(3)
Increase in Sales Prices Before Hedging	187	63	24	274
Change in Amounts Reclassified from AOCL	12	(1)	-	11
Sales Revenues, First Three Months of 2010	$ 407	$ 229	$ 52	$ 688

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the first quarter of 2010 as compared with the first quarter of 2009 due to the following:

- an increase in total consolidated average realized prices to almost twice that of first quarter 2009;
- increased production from the Wattenberg field in the northern region of our US operations due to ongoing development activity;
- additional production of approximately 3 MBpd for the month of March 2010 from DJ Basin assets acquired;
- commencement of crude oil production from a sidetrack to a Swordfish natural gas well;
- renewed production from Ticonderoga in the deepwater Gulf of Mexico which was off-line first quarter 2009 as a result of hurricane damage to third-party processing and pipeline facilities; and
- an increase in North Sea volumes due to facility enhancements at the Dumbarton field and the impact of the first well at Lochranza coming online;

offset by

- a decrease in Equatorial Guinea sales volumes due to timing of liftings and the planned shut-down of the Alba field for facilities maintenance and repair; and
- a decrease in volumes due to natural field decline in the Mid-Continent and Gulf Coast areas.

Revenues from crude oil and condensate sales included deferred losses of $5 million and $17 million for first quarter 2010 and 2009, respectively, reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges.

Natural gas sales – Revenues from natural gas sales increased during the first quarter of 2010 as compared with the first quarter of 2009 due to the following:

- a 44% increase in total consolidated average realized prices; and
- additional production of approximately 37 MMcfpd for the month of March 2010 from DJ Basin assets acquired;

offset by

- a decrease in Israel sales volumes due to lower demand for natural gas to produce electricity for heating, and a higher percentage of the demand met by imports from Egypt;
- a decrease in Equatorial Guinea sales volumes due to the planned shut-down of the Alba field for facilities maintenance and repair;
- a decrease in sales volumes due to the sidetrack of a Swordfish gas well into an oil zone after the gas zone began producing water; and
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas.

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Revenues from natural gas sales for the first quarter of 2010 included a decrease of $1 million reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges. Revenues for the first quarter of 2009 included a de minimis amount reclassified from AOCL.

NGL sales – Most of our US NGL production is from the Wattenberg field and deepwater Gulf of Mexico. NGL sales revenues increased during the first quarter of 2010 as compared with 2009 due to an increase in sales volumes from the Wattenberg field and an 82% increase in consolidated average realized prices.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore in Equatorial Guinea. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, our share of earnings is reported as income from equity method investees in our consolidated statements of operations, and our share of dividends is reported within cash flows from operating activities in our consolidated statements of cash flows.

The increase in income from equity method investees for the first quarter of 2010 as compared with 2009 was due to an increase in average realized condensate, LPG and methanol prices to approximately twice that of first quarter 2009, partially offset by a decrease in LPG sales volumes due to a planned plant shutdown for maintenance and repairs. Condensate and LPG sales volumes and average realized prices are included in the average daily sales volumes and average realized sales prices table above. Methanol sales volumes totaled 35 MMgal for both first quarter 2010 and 2009, and average realized methanol prices were 83 cents per gallon and 46 cents per gallon for first quarter 2010 and 2009, respectively.

The increase in dividends from equity method investees during the first quarter of 2010 as compared with 2009 was due to their increased profitability.

Other Revenues Other revenues include electricity sales and other revenues from operating activities. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Operating Costs and Expenses

Operating costs and expenses were as follows:

	Three Months Ended March 31, 2010	2009	Increase (Decrease) from Prior Year
(millions)			
Costs and Expenses			
Production Expense	$ 139	$ 130	7 %
Exploration Expense	80	42	90 %
Depreciation, Depletion and Amortization	216	200	8 %
General and Administrative	66	59	12 %
Asset Impairments	-	437	(100 %)
Other Operating Expense, Net	14	(6)	-
Total	$ 515	$ 862	(40 %)

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Changes in operating costs and expenses are discussed below.

Production Expense   Components of production expense were as follows:

(millions, except per unit)	Total per BOE (1)	Total	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate
Three Months Ended March 31, 2010							
Lease Operating Expense (2)	$ 5.12	$ 88	$ 65	$ 7	$ 2	$ 11	$ 3
Production and Ad Valorem Taxes	1.95	34	29	-	-	-	5
Transportation Expense	1.00	17	14	-	-	2	1
Total Production Expense	$ 8.07	$ 139	$ 108	$ 7	$ 2	$ 13	$ 9
Three Months Ended March 31, 2009							
Lease Operating Expense (2)	$ 5.50	$ 100	$ 77	$ 9	$ 1	$ 10	$ 3
Production and Ad Valorem Taxes	1.00	18	18	-	-	-	-
Transportation Expense	0.63	12	10	-	-	1	1
Total Production Expense	$ 7.13	$ 130	$ 105	$ 9	$ 1	$ 11	$ 4

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

(2) Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover expense.

For the first quarter of 2010, total production costs increased as compared with the first quarter of 2009 due to the following:

- an increase in production taxes in the US and China due to higher commodity prices;
- an increase in transportation expense in the Wattenberg field due to increased crude oil and condensate production and the use of a new interstate crude oil transportation pipeline system to market production; and
- an increase in North Sea lease operating expense due to higher sales volumes;

offset by

- reductions in US lease operating expense due to the abandonment of our remaining Gulf of Mexico shelf properties at Main Pass and reductions in third-party costs and operating supplies and services; and
- a reduction in Equatorial Guinea lease operating expense due to scheduled downtime at the Alba field for facilities maintenance and repair and a reduction in the volumes of crude oil and condensate lifted, which resulted in a portion of operating expenses being recorded as inventory cost.

Oil and Gas Exploration Expense   Components of oil and gas exploration expense were as follows:

(millions)	Total	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate (1)

Three Months Ended March 31, 2010						
Dry Hole Expense	$39	$36	$3	$ -	$-	$-
Seismic	22	22	-	-	-	-
Staff Expense	15	3	2	1	-	9
Other	4	4	-	-	-	-
Total Exploration Expense	$80	$65	$5	$ 1	$-	$9
Three Months Ended March 31, 2009						
Dry Hole Expense	$2	$(1)	$4	$ -	$-	$(1)
Seismic	23	23	-	-	-	-
Staff Expense	15	4	3	-	1	7
Other	2	2	-	-	-	-
Total Exploration Expense	$42	$28	$7	$ -	$1	$6

(1) Other international includes amounts spent in support of various international new ventures.

Oil and gas exploration expense for the first quarter of 2010 increased as compared with 2009. US dry hole expense was associated with the Double Mountain exploration well in the deepwater Gulf of Mexico which found noncommercial quantities of hydrocarbons. Seismic expense in each quarter was incurred in support of Central Gulf of Mexico lease sales.

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Depreciation, Depletion and Amortization   DD&A expense was as follows:

(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate
Three Months Ended March 31, 2010						
DD&A	$ 216	$181	$8	$ 4	$15	$8
Unit Rate Per BOE (1)	$ 12.57					
Three Months Ended March 31, 2009						
DD&A	$ 200	$169	$9	$ 5	$9	$8
Unit Rate Per BOE (1)	$ 11.01					

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for the first quarter of 2010 increased as compared with 2009 due to the following:

- higher production in the Wattenberg, Piceance and Western Oklahoma areas, which have high DD&A rates relative to production from Equatorial Guinea and Israel which have lower DD&A rates;
- ongoing capital spending in the Northern region of our US operations;
- higher production in the North Sea; and
- impact of lower year-end 2009 commodity prices on oil and gas reserves;

offset by

- lower DD&A expense in the Mid-Continent area which has a reduced net book value resulting from an impairment recorded at the end of 2009.

The unit rate per BOE increased for the first quarter of 2010 as compared with 2009 due to the change in mix of production, including decreases in lower-cost volumes from Equatorial Guinea and Israel and the impact of lower year-end 2009 commodity prices on oil and gas reserves, offset by a lower rate for the Mid-Continent area.

General and Administrative Expense   General and administrative expense (G&A) was as follows:

	Three Months Ended March 31, 2010	2009
G&A Expense (in millions)	$ 66	$ 59
Unit Rate per BOE (1)	$ 3.86	$ 3.23

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

G&A expense for the first quarter of 2010 increased as compared with 2009 primarily due to additional expenses relating to personnel and office costs in support of our major projects.

Asset Impairments   Asset impairment expense for first quarter 2009 was related to Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, and our Gulf of Mexico Main Pass asset which had been reclassified from held-for-sale to held-and-used.

Other Operating Expense, Net   Other operating expense, net includes electricity generation expense and other items of operating income or expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended March 31,		Increase (Decrease) from Prior Year
(millions)	2010	2009	
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	(145)	(73)	99%
Interest, Net of Amount Capitalized	20	18	11%
Other Non-Operating (Income) Expense, Net	-	8	(100%)
Total	(125)	(47)	166%

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(Gain) Loss on Commodity Derivative Instruments Gain on commodity derivative instruments consisted of a $2 million realized loss and a $147 million unrealized gain which was almost entirely related to a decline in natural gas prices subsequent to December 31, 2009. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 6. Fair Value Measurements and Disclosures.

Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

	Three Months Ended March 31,	
	2010	2009
(millions, except per unit)		
Interest Expense	$ 35	$ 24
Capitalized Interest	(15)	(6)
Interest Expense, Net	$ 20	$ 18
Unit Rate, per BOE (1)	$ 1.15	$ 0.99

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Interest expense increased first quarter 2010, as compared with 2009. The increase in interest expense primarily relates to our $1 billion 8¼% senior unsecured notes due March 1, 2019, which we issued on February 27, 2009. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility. See also Liquidity and Capital Resources – Financing Activities below.

The increases in the amount of interest capitalized are due to higher work in progress related to major long-term projects in West Africa, the deepwater Gulf of Mexico and Israel and the higher interest rate associated with our $1 billion, 8¼% senior unsecured notes due March 1, 2019.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense includes deferred compensation (income) expense, interest income and other (income) expense. The decrease was due to a reduction in deferred compensation expense and increases in interest and other income. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Income Tax Provision (Benefit)

See Item 1. Financial Statements – Note 11. Income Taxes for a discussion of the change in our effective tax rate during the first three months of 2010 as compared with 2009.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

We strive to employ a capital structure, emphasizing a strong balance sheet, and financing strategy designed to provide ample liquidity throughout the commodity price cycle, sufficient to fund growth and major project development. Specifically, we strive to retain the ability to fund long cycle capital intensive development projects while also maintaining the capability for financially attractive periodic mergers and acquisitions activity, such as the DJ Basin asset acquisition on March 1, 2010. We endeavor to maintain an investment grade debt rating in support of these objectives. We also utilize a commodity price hedging program to reduce commodity price uncertainty and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our operations and cash flows.

We expect to spend approximately $1 billion per year in 2010 and 2011 for major project development. We plan to fund these projects from cash on hand, cash flows from operations and borrowings under our revolving credit facility and/or other financing. Occasional sales of non-strategic crude oil and natural gas properties may also generate cash. During first quarter 2010, we maintained our strong financial capacity ending the quarter with over $1 billion in cash and significant remaining capacity under our credit facility for total liquidity of $2.5 billion.

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Information regarding cash and debt balances was as follows:

(millions, except percentages)	March 31, 2010	December 31, 2009
Cash and Cash Equivalents	$ 1,031	$ 1,014
Amount Available to be Borrowed Under Credit Facility	1,430	1,718
Total Liquidity	$ 2,461	$ 2,732
Total Debt (Excluding Unamortized Discount)	$ 2,373	$ 2,045
Total Shareholders' Equity	6,395	6,157
Debt-to-Capital Ratio (1)	27 %	25 %

(1) We define our ratio of debt-to-book capital as total debt (which includes both long-term debt, excluding unamortized discount, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Cash and Cash Equivalents   We had $1 billion in cash and cash equivalents at March 31, 2010, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. A majority of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently intend to use our international cash to fund international projects, including the planned developments in West Africa and Israel.

Credit Facility   We have an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. During first quarter 2010, we drew down on our facility to fund the DJ Basin asset acquisition, yet ended the quarter with $1.4 billion remaining available for borrowing.

Commodity Derivative Instruments   We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments include variable to fixed commodity price swaps, collars and basis swaps. Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments. Except for certain minor derivative contracts that we enter into from time to time in order to market third-party natural gas, none of our counterparty agreements contain margin requirements.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of March 31, 2010 the fair value of our commodity derivative assets was $79 million and the fair value of our commodity derivative liabilities was $29 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities for a discussion of counterparty credit risk and Note 6. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of commodity derivative instruments.

Cash Flows
Cash flow information is as follows:

Three Months Ended
March 31,

(millions)	2010	2009
Total Cash Provided By (Used in)		
Operating Activities	$ 588	$ 185
Investing Activities	(849)	(399)
Financing Activities	278	91
Increase (Decrease) in Cash and Cash Equivalents	$ 17	$ (123)

Operating Activities   Net cash provided by operating activities for the first three months of 2010 increased as compared with the first three months of 2009 due primarily to increases in commodity prices and the $84 million refund of deepwater Gulf of Mexico royalties.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties, which may be offset by proceeds from property sales. Net cash used in investing activities increased by $450 million during the first three months of 2010 as compared with the first three months of 2009, primarily due to the DJ Basin asset acquisition. See Item 1. Financial Statements – Note 3. DJ Basin Asset Acquisition. See also Investing Activities – Acquisition, Capital and Exploration Expenditures below.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first three months of 2010, $288 million of funds were provided by net increases in borrowings under our revolving credit facility, primarily to fund the DJ Basin asset acquisition. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($34 million). We used cash to pay dividends on our common stock ($32 million) and to repurchase shares of our common stock ($12 million).

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In comparison, during the first three months of 2009, funds were provided by net proceeds from the issuance of our 8¼% senior notes ($989 million) and cash proceeds from, and tax benefits related to, the exercise of stock options ($14 million). We used cash for net repayments of amounts outstanding under our revolving credit facility ($880 million), to pay dividends on our common stock ($31 million), and to repurchase shares of our common stock ($1 million).

Investing Activities

Acquisition, Capital and Exploration Expenditures   Information for investing activities (on an accrual basis) is as follows:

	Three Months Ended March 31,	
	2010	2009
(millions)		
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition	$ 146	$ 16
Proved Property Acquisition	363	-
Exploration	115	95
Development	274	231
Corporate and Other	20	44
Total	$ 918	$ 386
Increase in Obligation under FPSO Lease	$ 40	$ -

2010   Unproved and proved property acquisition costs for first quarter are the result of the DJ Basin asset acquisition. See Item 1. Financial Statements – Note 3. DJ Basin Asset Acquisition.

The obligation under FPSO lease represents the increase in estimated construction in progress to date on an FPSO to be used in the development of the Aseng field in Equatorial Guinea. See Item 1. Financial Statements – Note 4. Debt.

2009   Unproved property acquisition costs included primarily lease bonuses on deepwater Gulf of Mexico lease blocks.

Financing Activities

Long-Term Debt   Our principal source of liquidity is an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the credit facility. The credit facility is with certain commercial lending institutions and is available for general corporate purposes.

At March 31, 2010, borrowings outstanding under the credit facility totaled $670 million, leaving approximately $1.4 billion available for use. The weighted average interest rate applicable to borrowings under the credit facility at March 31, 2010 was 0.55%.

Our outstanding fixed-rate debt totaled $1.6 billion at March 31, 2010. The weighted average interest rate on fixed-rate debt was 7.73%, with maturities ranging from 2014 to 2097.

Our ratio of debt-to-book capital was 27% at March 31, 2010 and 25% at December 31, 2009. We define our ratio of debt-to-book capital as total debt (which includes both long-term debt, excluding unamortized discount, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Short-Term Borrowings   Our committed credit facility may be supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no amounts outstanding under uncommitted credit lines at March 31, 2010 or December 31, 2009. Depending upon future credit market conditions, these sources may or may not be available. However, we are not dependent on them to fund our day-to-day operations.

Dividends   We paid common stock dividends of 18 cents per share during the first three months of 2010 and 18 cents per share during the first three months of 2009. On April 26, 2010, our Board of Directors declared a quarterly cash dividend of 18 cents per common share, payable May 24, 2010 to shareholders of record on May 10, 2010. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options   We received cash proceeds of $21 million from the exercise of stock options during the first three months of 2010 as compared with $11 million during the first three months of 2009.

Common Stock Repurchases   We receive shares of common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received 161,447 shares with a value of $12 million during the first three months of 2010 and 17,510 shares with a value of $1 million during the first three months of 2009.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to market risk in the normal course of business operations, and the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to price changes.

At March 31, 2010, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Our open commodity derivative instruments were in a net receivable position with a fair value of $50 million. Based on the March 31, 2010 published commodity futures price strips for the underlying commodities, a price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately $10 million. A price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately $12 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our revolving credit facility and other variable-rate debt and the amount of interest we earn on our short-term investments.

At March 31, 2010, we had $2.3 billion (excluding unamortized discount) of long-term debt outstanding. Of this amount, $1.6 billion was fixed-rate debt with a weighted average interest rate of 7.73%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss.

The remainder of our long-term debt, $670 million at March 31, 2010, was variable-rate debt drawn under our credit facility. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the March 31, 2010 balance of our variable-rate debt would result in a change in annual interest expense of approximately $2 million.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At March 31, 2010, AOCL included $9 million, net of tax, related to interest rate derivative instruments. Of this amount, $2 million, net of tax, is currently being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014. The remainder is related to the change in fair value of an interest rate forward starting swap. See Item 8. Financial Statements and Supplementary Data – Note 5. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of March 31, 2010, our cash and cash equivalents totaled $1 billion, approximately 73% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of March 31, 2010 would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. An increase in exchange rates between the US dollar and the currency of the foreign tax jurisdiction in which these liabilities are located could result in the use of additional cash to settle these liabilities. Transaction gains or losses were not material in any of the periods presented and are included in other (income) expense, net in the consolidated statements of operations.

In the UK sector of our North Sea operations, significant future capital commitments and certain operating expenses are expected to be denominated in British pounds. Therefore, our cash flows could be impacted by future changes in the exchange rate between the US dollar and the British pound. We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determined that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

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Disclosure Regarding Forward-Looking Statements

This quarterly report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “anticipate,” “estimate” ar similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors included herein, if any, and included in our Annual Report on Form 10-K for the year ended December 31, 2009, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2009 is available on our website at www.nobleenergyinc.com.

Item 4. Controls and Procedures

Based on the evaluation of our disclosure controls and procedures by our principal executive officer and our principal financial officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective. There were no changes in internal control over financial reporting that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See Item I. Financial Statements – Note 15. Commitments and Contingencies.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our annual report on Form 10-K for the year ended December 31, 2009, other than the following:

Our operations in the deepwater Gulf of Mexico could be adversely impacted by the recent drilling rig accident and resulting oil spill.

On Thursday, April 22, 2010, a deepwater Gulf of Mexico drilling rig, Deepwater Horizon, that was engaged in drilling operations for another operator, sank after an apparent blowout and fire. Although attempts are being made to seal the well, hydrocarbons have been leaking and the spill area continues to grow. We recently began drilling an exploratory well at our Santiago prospect (Galapagos project) which may be threatened by the spill. If conditions continue to deteriorate, we may be forced to suspend drilling operations.

We have significant exploration and development programs ongoing in the deepwater Gulf of Mexico. At this time, we cannot predict the full impact of the incident and resulting spill on our drilling schedule or operations. In addition, we cannot predict how government agencies will respond to the incident or whether changes in laws and regulations concerning operations in the Gulf of Mexico, including the ability to obtain drilling permits, will result.

Significant delays in our drilling schedule, damage to production facilities caused by the spill, or changes in regulations regarding future exploration and production activities in the Gulf of Mexico could increase our drilling and operating costs resulting in reduced cash flows and profitability.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
01/01/10 - 01/31/10	31,065	$ 74.97	-	-
02/01/10 - 02/28/10	128,001	75.09	-	-
03/01/10 - 03/31/10	2,381	75.17	-	-
Total	161,447	$ 75.07	-	-

(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under stock-based compensation plans.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NOBLE ENERGY, INC.
(Registrant)

Date April 29, 2010	/s/ Kenneth M. Fisher Kenneth M. Fisher Senior Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Incorporation, as amended through May 16, 2005, of the Registrant (filed as Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 19, 2009 and incorporated herein by reference).
31.1	Certification of the Company's Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	Certification of the Company's Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	Certification of the Company's Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	Certification of the Company's Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
101	The following materials from the Noble Energy, Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Shareholders' Equity, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.