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

FORM 10-Q

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

For the quarterly period ended March 31, 2011

OR

o 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 x No o

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 x No o

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 x   Accelerated filer o   Non-accelerated filer o   Smaller reporting company o
(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 o   No x

As of April 15, 2011, there were 176,466,238 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
(millions, except per share amounts)
(unaudited)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Revenues		
Oil, Gas and NGL Sales	$830	$688
Income from Equity Method Investees	48	26
Other Revenues	21	19
Total	899	733
Costs and Expenses		
Production Expense	142	139
Exploration Expense	70	80
Depreciation, Depletion and Amortization	221	216
General and Administrative	83	66
Other Operating (Income) Expense, Net	36	14
Total	552	515
Operating Income	347	218
Other (Income) Expense		
(Gain) Loss on Commodity Derivative Instruments	286	(145)
Interest, Net of Amount Capitalized	16	20
Other Non-Operating (Income) Expense, Net	8	-
Total	310	(125)
Income Before Income Taxes	37	343
Income Tax Provision	23	106
Net Income	$14	$237
Earnings Per Share, Basic	$0.08	$1.36
Earnings Per Share, Diluted	0.08	1.34
Weighted Average Number of Shares Outstanding, Basic	176	174
Weighted Average Number of Shares Outstanding, Diluted	178	177

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

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

	March 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,419	$1,081
Accounts Receivable, Net	565	556
Other Current Assets	207	201
Total Assets, Current	2,191	1,838
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	14,893	14,393
Property, Plant and Equipment, Other	276	263
Total Property, Plant and Equipment, Gross	15,169	14,656
Accumulated Depreciation, Depletion and Amortization	(4,608)	(4,392)
Total Property, Plant and Equipment, Net	10,561	10,264
Goodwill	696	696
Other Noncurrent Assets	519	484
Total Assets	$13,967	$13,282
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$897	$927
Other Current Liabilities	403	495
Total Liabilities, Current	1,300	1,422
Long-Term Debt	2,801	2,272
Deferred Income Taxes, Noncurrent	2,175	2,110
Other Noncurrent Liabilities	815	630
Total Liabilities	7,091	6,434
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3 per share; 250 Million Shares Authorized; 196 Million and 195 Million Shares Issued, Respectively	654	651
Additional Paid in Capital	2,427	2,385
Accumulated Other Comprehensive Loss	(87)	(104)
Treasury Stock, at Cost; 19 Million Shares	(640)	(624)
Retained Earnings	4,522	4,540
Total Shareholders' Equity	6,876	6,848
Total Liabilities and Shareholders' Equity	$13,967	$13,282

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

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

	Three Months Ended March 31,	
	2011	2010
Cash Flows From Operating Activities		
Net Income	$14	$237
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	221	216
Dry Hole Cost	22	39
Deferred Income Taxes	11	27
Dividends (Income) from Equity Method Investees, Net	(23)	(13)
Unrealized (Gain) Loss on Commodity Derivative Instruments	303	(147)
Other Adjustments for Noncash Items Included in Income	36	21
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	(9)	85
(Increase) Decrease in Other Current Assets	(17)	50
Increase in Accounts Payable	28	27
Increase (Decrease) in Current Income Taxes Payable	(71)	58
(Decrease) in Other Current Liabilities	(54)	(25)
Other Operating Assets and Liabilities, Net	23	13
Net Cash Provided by Operating Activities	484	588
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(578)	(383)
Central DJ Basin Asset Acquisition	-	(466)
Proceeds from Sale of Property, Plant and Equipment	3	-
Net Cash Used in Investing Activities	(575)	(849)
Cash Flows From Financing Activities		
Exercise of Stock Options	23	21
Excess Tax Benefits from Stock-Based Awards	8	13
Dividends Paid, Common Stock	(32)	(32)
Purchase of Treasury Stock	(16)	(12)
Proceeds from Credit Facilities	120	610
Repayment of Credit Facilities	(470)	(322)
Proceeds from Issuance of Senior Long-Term Debt, Net	836	-
Settlement of Interest Rate Derivative Instrument	(40)	-
Net Cash Provided By Financing Activities	429	278
Increase in Cash and Cash Equivalents	338	17
Cash and Cash Equivalents at Beginning of Period	1,081	1,014
Cash and Cash Equivalents at End of Period	$1,419	$1,031

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

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

	Common Stock	Additional Paid in Capital	Acumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2010	$ 651	$ 2,385	$ (104)	$ (624)	$ 4,540	$ 6,848
Net Income	-	-	-	-	14	14
Stock-based Compensation	-	14	-	-	-	14
Exercise of Stock Options	2	21	-	-	-	23
Tax Benefits Related to Exercise of Stock Options	-	8	-	-	-	8
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Dividends (18 cents per share)	-	-	-	-	(32)	(32)
Changes in Treasury Stock, Net	-	-	-	(16)	-	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	15	-	-	15
Net Change in Other	-	-	2	-	-	2
March 31, 2011	$ 654	$ 2,427	$ (87)	$ (640)	$ 4,522	$ 6,876
December 31, 2009	$ 645	$ 2,260	$ (75)	$ (615)	$ 3,942	$ 6,157
Net Income	-	-	-	-	237	237
Stock-based Compensation	-	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						
	-	-	(7)	-	-	(7)

Unrealized Change in Fair Value						
March 31, 2010	$ 649	$ 2,304	$ (78)	$ (627)	$ 4,147	$ 6,395

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

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 a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our key operating areas are onshore in the US, primarily in the DJ Basin, in the Deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) 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 GAAP for complete financial statements. The accompanying consolidated financial statements at March 31, 2011 and December 31, 2010 and for the three months ended March 31, 2011 and 2010 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three months ending March 31, 2011 are not necessarily indicative of the results that may be expected for the year ended December 31, 2011. 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, 2010.

Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

Estimates The preparation of consolidated financial statements in conformity with US 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,	
	2011	2010
(millions)		
Other Revenues		
Electricity Sales (1)	$21	$19
Total	$21	$19
Production Expense		
Lease Operating Expense	$92	$88
Production and Ad Valorem Taxes	32	34
Transportation Expense	18	17
Total	$142	$139

Other Operating (Income) Expense, Net		
Deepwater Gulf of Mexico Moratorium Expense (2)	$18	$-
Electricity Generation Expense (1)	17	10
Other, Net	1	4
Total	$36	$14
Other Non-Operating (Income) Expense, Net		
Deferred Compensation (3)	$10	$2
Interest Income	(3)	(1)
Other (Income) Expense, Net	1	(1)
Total	$8	$-

(1) Electricity sales include sales from the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including DD&A and changes in the allowance for doubtful accounts.

(2) Amount primarily relates to rig stand-by expense incurred prior to receiving permit to resume drilling activities in the Deepwater Gulf of Mexico.

(3) 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, 2011	December 31, 2010
Accounts Receivable, Net		
Commodity Sales	$314	$ 291
Joint Interest Billings	231	259
Other	45	33
Allowance for Doubtful Accounts	(25)	(27)
Total	$565	$ 556
Other Current Assets		
Inventories, Current	$119	$ 112
Commodity Derivative Assets, Current	2	62
Deferred Income Taxes, Net, Current	55	8
Prepaid Expenses and Other Assets, Current	31	19
Total	$207	$ 201
Other Noncurrent Assets		
Equity Method Investments	$309	$ 285
Mutual Fund Investments	117	112
Other Assets, Noncurrent	93	87
Total	$519	$ 484
Accounts Payable - Trade		
Capital Costs	$580	$ 642
Royalties Payable	107	94
Lease Operating Expense	29	29
Other	181	162
Total	$897	$ 927
Other Current Liabilities		
Production and Ad Valorem Taxes	$110	$ 110
Commodity Derivative Liabilities, Current	119	24
Interest Rate Derivative Liability, Current	-	63
Income Taxes Payable	19	90
Asset Retirement Obligations, Current	45	45
Interest Payable	30	36
Other	80	127
Total	$403	$ 495
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$247	$ 229
Asset Retirement Obligations, Noncurrent	209	208
Accrued Benefit Costs, Noncurrent	78	76
Commodity Derivative Liabilities, Noncurrent	200	51
Other	81	66
Total	$815	$ 630

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

Note 3. Debt

Our debt consists of the following:

	March 31, 2011			December 31, 2010		
	Debt	Interest Rate		Debt	Interest Rate	
(millions, except percentages)						
Credit Facility, due December 9, 2012	$-	-		$350	0.57	%
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	%
6% Senior Notes, due March 1, 2041	850	6.00	%	-	-	
7¼% Senior Debentures, due August 1, 2097	84	7.25	%	84	7.25	%
FPSO Lease Obligation (1)	329	-		295	-	
Total	2,813			2,279		
Unamortized Discount	(12)			(7)		
Total Debt, Net of Discount	$2,801			$2,272		

(1) Amount reported is based on percentage of floating production, storage and offloading vessel (FPSO) construction activities completed as of the reporting dates, and therefore does not reflect future minimum lease obligations. The increase in the FPSO lease obligation is a non-cash financing activity.

Debt Issuance On February 18, 2011, we closed an offering of $850 million senior unsecured notes receiving net proceeds of $836 million, after deducting discount and underwriting fees. The notes are due March 1, 2041, and pay interest semi-annually at 6%. Total debt issuance costs of approximately $9 million were incurred and are being amortized to expense over the term of the note. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility and the balance of the proceeds will be used for general corporate purposes. The notes are senior unsecured debt and will rank pari passu with any of our other senior unsecured indebtedness with respect to the payment of both principal and interest.

Annual Maturities Annual maturities of outstanding debt, excluding FPSO lease payments, are as follows:

	As of March 31, 2011
(millions)	
2011	$-
2012	-
2013	-
2014	200
2015	-
Thereafter	2,284

Total	$2,484

Note 4. Derivative Instruments and Hedging Activities

Objective 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, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

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(unaudited)

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also enter into forward contracts or swap agreements to hedge exposure to interest rate risk.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 5. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk   Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of highly rated major banks or market participants, and we control our level of financial exposure. Our commodity derivative contracts 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 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 or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated debt issuance. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million. Approximately $26 million, net of tax, will remain in accumulated other comprehensive loss (AOCL) and be reclassified into interest expense over the term of the note. The ineffective portion of the interest rate swap was de minimis. See Note 3. Debt.

Unsettled Derivative Instruments   As of March 31, 2011, we had entered into the following crude oil derivative instruments:

				Swaps		Collars	
Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2011	Swaps	NYMEX WTI (1)	5,000	$85.52	$-	$-	$-

2011	Two-Way Collars	NYMEX WTI	13,000	-	-	80.15	94.63
2011	Three-Way Collars	NYMEX WTI	12,000	-	58.33	78.33	100.71
2012	Swaps	NYMEX WTI	5,000	91.84	-	-	-
2012	Swaps	Dated Brent	8,000	89.06	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	12,000	-	75.83	97.50	125.93

(1) West Texas Intermediate

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Noble Energy, Inc.
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(unaudited)

As of March 31, 2011, we had entered into the following natural gas derivative instruments:

				Swaps		Collars	
Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2011	Swaps	NYMEX HH(1)	25,000	$6.41	$-	$-	$-
2011	Two-Way Collars	NYMEX HH	140,000	-	-	5.95	6.82
2011	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.00	6.70
2012	Swaps	NYMEX HH	30,000	5.10	-	-	-
2012	Three-Way Collars	NYMEX HH	110,000	-	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
2013	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.25	5.59

(1) Henry Hub

As of March 31, 2011, we had entered into the following natural gas basis swaps:

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2011	IFERC CIG(1)	NYMEX HH	140,000	$ (0.70)
2012	IFERC CIG	NYMEX HH	150,000	(0.52)

(1) Colorado Interstate Gas – Northern System

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, 2011		December 31, 2010		March 31, 2011		December 31, 2010	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		$ 2		$ 62		$ 119		$ 24

Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets		Current Assets		Current Liabilities		Current Liabilities	
	Noncurrent Assets	-	Noncurrent Assets	-	Noncurrent Liabilities	200	Noncurrent Liabilities	51
Interest Rate Derivative Instruments (Designated as Hedging Instruments)	Current Assets	-	Current Assets	-	Current Liabilities	-	Current Liabilities	63
Total		$ 2		$ 62		$ 319		$ 138

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

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, 2011	Three Months Ended March 31, 2010
(millions)		
Realized Mark-to-Market (Gain) Loss	$(17)	$2
Unrealized Mark-to-Market (Gain) Loss	303	(147)
Total (Gain) Loss on Commodity Derivative Instruments	$286	$(145)

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,			
	2011	2010	2011	2010
(millions)				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$-	$-	$-	$5
Natural Gas Derivative Instruments	-	-	-	1
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	(23)	11	-	-
Total	$(23)	$11	$-	$6

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. All net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, had been reclassified to earnings by December 31, 2010.

AOCL at March 31, 2011 included deferred losses of $28 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified into earnings as an adjustment to interest expense over the terms of our Senior Notes due April 2014 and March 2041. Approximately $2 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 5. 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, two-way and three-way collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves 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 nonperformance 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 values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 4. Derivative Instruments and Hedging Activities.

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Noble Energy, Inc.
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(unaudited)

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 nonperformance 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. See Note 4. Derivative Instruments and Hedging Activities.

Deferred Compensation Liability   The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See Mutual Fund Investments above.

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

	Fair Value Measurements Using				
(millions)	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, 2011					
Financial Assets					
Mutual Fund Investments	$117	$-	$ -	$-	$ 117
Commodity Derivative Instruments	-	80	-	(78)	2
Financial Liabilities					
Commodity Derivative Instruments	-	(397)	-	78	(319)
Portion of Deferred Compensation Liability Measured at Fair Value	(191)	-	-	-	(191)
December 31, 2010					
Financial Assets					
Mutual Fund Investments	$112	$-	$ -	$-	$ 112
Commodity Derivative Instruments	-	106	-	(44)	62
Financial Liabilities					
Commodity Derivative Instruments	-	(119)	-	44	(75)
Interest Rate Derivative Instrument	-	(63)	-		(63)
Portion of Deferred Compensation Liability Measured at Fair Value	(178)	-	-	-	(178)

(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.

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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 carrying amount of floating-rate debt approximates fair value because the interest rate paid on such debt is set for periods of three months or less. See Note 3. Debt.

Fair value information regarding our debt is as follows:

	March 31, 2011		December 31, 2010	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net of Unamortized Discount (1)	$2,472	$2,828	$1,977	$2,302

(1) Excludes FPSO lease obligation.

Note 6. 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, 2011
Capitalized Exploratory Well Costs, Beginning of Period	$426
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	80
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves (1)	(18)
Capitalized Exploratory Well Costs Charged to Expense	(15)
Capitalized Exploratory Well Costs, End of Period	$473

(1) Includes $13 million related to the Flyndre project in the North Sea.

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, 2011	December 31, 2010
Exploratory Well Costs Capitalized for a Period of One Year or Less	$171	$ 148
	302	278

Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling		
Balance at End of Period	$473	$ 426
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	8	9

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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, 2011:

	Suspended Since			
(millions)	Total	2010	2009	2008 & Prior
Project				
Blocks O and I (West Africa)	$102	$3	$14	$85
YoYo (West Africa)	34	-	-	34
Dalit (Israel)	20	-	20	-
Deep Blue (Deepwater Gulf of Mexico)	52	33	19	-
Gunflint (Deepwater Gulf of Mexico)	52	-	3	49
Redrock (Deepwater Gulf of Mexico)	17	-	-	17
Selkirk (North Sea)	20	-	-	20
Other	5	-	2	3
Total Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	$302	$36	$58	$208

Blocks O and I (West Africa)   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries located offshore Equatorial Guinea.   We are evaluating future crude oil and natural gas projects and are currently appraising the Diega/Carmen area, offshore Equatorial Guinea.

YoYo (West Africa)   The YoYo mining concession is a 2007 natural gas and condensate discovery located offshore Cameroon. We recently completed a 3-D seismic acquisition, and results are being processed for further drilling potential.

Dalit (Israel)   Dalit is a 2009 natural gas discovery located offshore Israel. We are currently working with our partners on a cost-effective development plan.

Deep Blue (Deepwater Gulf of Mexico) Deep Blue (Green Canyon Block 723) was a significant test well, which began drilling during 2009. When the Deepwater Gulf of Mexico moratorium was announced in May 2010, we were required to suspend sidetrack drilling activities. Once a drilling permit is approved, we plan to resume exploration activities.

Gunflint (Deepwater Gulf of Mexico)   Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. Our plans to drill one or two appraisal wells in 2010 were delayed by the Deepwater Gulf of Mexico moratorium. Once a drilling permit is approved, we plan to drill one or two appraisal wells. We are also reviewing host platform options.

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). We are in the process of tying back Raton South to a host platform at Viosca Knoll Block 900. We plan to tie back Redrock after Raton South commences production, which is currently expected to occur by the end of 2011.

Selkirk (North Sea) The Selkirk project is 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.

Note 7. 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,	
	2011	2010
(millions)		
Asset Retirement Obligations, Beginning Balance	$253	$232
Liabilities Incurred	1	14
Liabilities Settled	(9)	(4)
Revision of Estimate	4	4
Accretion Expense	5	4
Asset Retirement Obligations, Ending Balance	$254	$250

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Liabilities settled in 2011 related primarily to Deepwater Gulf of Mexico and Gulf of Mexico shelf properties.

Liabilities incurred in 2010 were due to the Central DJ Basin asset acquisition.

Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 8. 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, 2011	Three Months Ended March 31, 2010
(millions)		
Service Cost	$ 4	$ 4
Interest Cost	3	3
Expected Return on Plan Assets	(4)	(3)
Other	2	1
Net Periodic Benefit Cost	$ 5	$ 5

During the three months ended March 31, 2011, we made cash contributions of $2 million to the pension plan.

Note 9. Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
(millions)		
Stock-Based Compensation Expense	$ 14	$ 14
Tax Benefit Recognized	(5)	(5)

During the three months ended March 31, 2011, we granted stock options and awarded shares of restricted stock (subject to service conditions) as follows:

	Number Granted/Awarded	Weighted Average Grant-Date Fair Value
Stock Options	965,423	$ 30.21

Shares of Restricted Stock	394,922	$ 90.37

On April 26, 2011, our stockholders approved the amendment and restatement of our 1992 Stock Option and Restricted Stock Plan to increase the number of shares of common stock authorized for issuance under the plan from 24 million to 31 million and modify certain plan provisions.

Note 10. Basic and Diluted Earnings Per Share

Basic earnings 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 per share:

	Three Months Ended March 31,	
	2011	2010
(millions, except per share amounts)		
Net Income	$ 14	$ 237
Net Income Used for Diluted Earnings Per Share Calculation	$ 14	$ 237
Weighted Average Number of Shares Outstanding, Basic	176	174
Incremental Shares from Assumed Conversion of Dilutive Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	2	3
Weighted Average Number of Shares Outstanding, Diluted	178	177
Earnings Per Share, Basic	$ 0.08	$ 1.36
Earnings Per Share, Diluted	0.08	1.34
Number of antidilutive stock options, shares of restricted stock and common shares held in a rabbi trust excluded from calculation above	2	1

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Note 11. Income Taxes

The income tax provision consists of the following:

	Three Months Ended March 31,	
	2011	2010
(millions)		
Current	$12	$79
Deferred	11	27
Total Income Tax Provision	$23	$106
Effective Tax Rate	62 %	31 %

Our effective tax rate increased for the first three months of 2011 as compared with the first three months of 2010. This increase was due primarily to an increase of $11 million in the valuation allowance against our deferred tax asset for foreign tax credits.

Recent Changes in Israeli Tax Law – In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes a special levy on income from oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We expect these changes to increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010.

Recent Changes in UK Tax Law – Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas production in the UK from 20% to 32% effective March 24, 2011. We expect this change to become law later in 2011. We expect the change will increase the tax rate on our UK oil and gas income from 50% to 62% and increase our 2011 consolidated effective income tax rate by approximately four percentage points. The change will also result in a remeasurement of our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. These changes will be reflected in our balance sheet and results of operations when the Finance Bill 2011 is enacted, which we expect to occur second quarter 2011.

Years Remaining Open to Examination – 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 – 2009.

Note 12. Comprehensive Income

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

	Three Months Ended March 31,	
	2011	2010
(millions)		

Net Income	$14	$237
Other Items of Comprehensive Income (Loss)		
Oil and Gas Cash Flow Hedges		
Realized Losses Reclassified Into Earnings	-	6
Less Tax Provision	-	(2)
Interest Rate Cash Flow Hedges		
Unrealized Change in Fair Value	23	(11)
Less Tax Provision	(8)	4
Net Change in Other	2	-
Other Comprehensive Income (Loss)	17	(3)
Comprehensive Income	$31	$234

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Note 13. 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, development, and acquisition: 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. Other International includes China, Ecuador, and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l and Corporate
Three Months Ended March 31, 2011						
Revenues from Third Parties	$ 851	$505	$130	$ 52	$114	$50
Income from Equity Method Investees	48	-	48	-	-	-
Total Revenues	899	505	178	52	114	50
DD&A	221	167	10	4	28	12
(Gain) Loss on Commodity Derivative Instruments	286	192	94	-	-	-
Income (Loss) Before Income Taxes	37	(37)	74	39	68	(107)
Three Months Ended March 31, 2010						
Revenues from Third Parties	$ 713	$510	$61	$ 33	$66	$43
Reclassification from AOCL (1)	(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) Loss on Commodity Derivative Instruments	(145)	(145)	-	-	-	-
Income (Loss) Before Income Taxes	343	289	66	26	36	(74)
March 31, 2011						
Goodwill	$ 696	$696	$-	$ -	$-	$-
Total Assets	13,967	9,520	2,382	1,011	766	288
December 31, 2010						
Goodwill	696	696	-	-	-	-
Total Assets	13,282	9,091	2,270	919	770	232

(1) 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. All hedge gains and losses had been reclassified to revenues by December 31, 2010.

Note 14. 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 global crude oil and natural gas exploration and production. Our strategy is to achieve growth in earnings and cash flows through the continued expansion of a high quality portfolio of 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 2011 included:

- net income of $14 million, as compared with $237 million for first quarter 2010;
- loss on commodity derivative instruments of $286 million (including unrealized mark-to-market loss of $303 million) as compared with a gain on commodity derivative instruments of $145 million (including unrealized mark-to-market gain of $147 million) for first quarter 2010;
- diluted earnings per share of $0.08, as compared with $1.34 for first quarter 2010;
- cash flow provided by operating activities of $484 million, as compared with $588 million for first quarter 2010;
- capital spending, on a cash basis, of $578 million, as compared with $849 million (including $466 million for the Central DJ Basin asset acquisition) for first quarter of 2010;
- issuance of $850 million of 30-year unsecured notes resulting in enhanced liquidity position of over $3.5 billion between cash and available credit; and
- ratio of debt-to-book capital of 29% as compared with 25% at December 31, 2010.

Significant operational events for first quarter 2011 included:

Overall

- increased total sales volumes 9% from first quarter 2010 to 215 MBoe/d;

United States Onshore

- drilled 12 horizontal wells in the DJ Basin, nine of which were in the Wattenberg Area;

Deepwater Gulf of Mexico

- received industry's first drilling permit post-moratorium to resume Deepwater Gulf of Mexico drilling at the Santiago prospect;

International

- a 34% increase in total sales volumes in Equatorial Guinea as compared with first quarter 2010;
- finalized field development drilling and completion work at the Aseng oil project offshore Equatorial Guinea;
- a 61% increase in natural gas sales volumes in Israel as compared with first quarter 2010;
- suspended drilling operations at the deeper portion of the Leviathan-1 well (offshore Israel) due to the identification of wear on the wellbore casing;
- initiated drilling at the Leviathan-2 appraisal well (offshore Israel);

- initiated development drilling at the Tamar field (offshore Israel); and
- completed seismic acquisition of 3-D data offshore Nicaragua and 2-D data offshore France.

Exploration Program

We have significant remaining exploration potential, primarily in the onshore US, Deepwater Gulf of Mexico, offshore West Africa, Eastern Mediterranean and other international areas where we hold acreage positions. Updates of our significant exploration activities are as follows:

North America Onshore – We continue to acquire seismic information and appraise our acreage in the DJ Basin and other onshore areas.

Santiago Prospect (Deepwater Gulf of Mexico) – On February 28, 2011, we received the industry's first approved permit to resume exploratory drilling since the suspension of all drilling operations by the Deepwater Gulf of Mexico moratorium. We resumed drilling at the Santiago exploratory well in April 2011 and expect results during second quarter 2011.

Deep Blue Prospect (Deepwater Gulf of Mexico) – We are currently working with the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) for approval of a permit to resume exploratory drilling which had been suspended by the Deepwater Gulf of Mexico moratorium.

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Gunflint Project (Deepwater Gulf of Mexico) – Once a drilling permit is approved by the BOEMRE, we plan to conduct appraisal drilling to help define the extent of the reservoir and a potential development scenario.

Offshore West Africa – We are currently appraising the Diega/Carmen area, offshore Equatorial Guinea.

Offshore Eastern Mediterranean – We are in the process of drilling the Leviathan-2 appraisal well, continuing interpretation of 3-D seismic information on our acreage offshore Israel, and preparing to conduct additional seismic testing on our acreage offshore Cyprus.

Other New Ventures – We continue to acquire and evaluate seismic information and order long-lead time equipment in support of future exploratory drilling activities in other international areas.

Major Development Projects

During first quarter 2011, we continued to advance our major development projects. Updates on our significant development projects are as follows:

DJ Basin (North America Onshore) – We have increased our horizontal drilling activity targeting the Niobrara formation, are currently operating four horizontal drilling rigs, and are continuing to appraise our Northern Colorado and Southern Wyoming acreage.

Galapagos Project(Deepwater Gulf of Mexico)– We received a permit and resumed exploratory drilling at the Santiago exploration well in April 2011. Installation of topside equipment at the host facility and subsea tiebacks for the Santa Cruz and Isabela wells are progressing. We currently expect production to commence in early 2012.

Aseng Project (Offshore Equatorial Guinea)– Drilling and completion work on the 10 subsea wells concluded in March 2011. Subsea production equipment fabrication and testing have also been completed. FPSO conversion is progressing and we currently expect production to commence in the first half of 2012.

Alen Project(Offshore Equatorial Guinea)– We are moving forward on the Alen project. All major subsea and platform contracts have been awarded, and platform equipment and drilling rig negotiations are under way. We currently expect production to commence by the end of 2013.

Leviathan Prospect (Offshore Israel) – During first quarter 2011, we continued drilling a deeper portion of the Leviathan-1 well in order to evaluate two additional intervals. Late in the quarter, we suspended drilling operations due to the identification of wear on the wellbore casing. Further drilling will require additional material and equipment. We are working to secure the needed items, which are not available in Israel, and expect to resume drilling later in 2011. We are evaluating potential development scenarios for the original Leviathan natural gas discovery.

Tamar Project (Offshore Israel) – Subsequent to the suspension of drilling activities at the deeper portion of the Leviathan-1 well, we moved the drilling rig to the Tamar field and commenced development drilling. All major installation contracts for the Tamar project have been awarded, the platform deck and jacket are being fabricated, and Tamar remains on schedule for commissioning in late 2012.

See Operating Outlook - Impact of Japanese Earthquake and Tsunami below.

Sales Volumes

On a BOE basis, total sales volumes were 9% higher first quarter 2011 as compared with first quarter 2010, and our mix of sales volumes was 40% global liquids, 31% international natural gas, and 29% US natural gas. International sales volumes were higher in Equatorial Guinea, Israel and the North Sea. US production decreased slightly year to year. Our volumes for first quarter 2010 included natural gas in Ecuador, where our production sharing contract (PSC) was terminated in late 2010 and production from certain Oklahoma assets and our Illinois Basin assets that were sold in 2010.

Commodity Price Changes and Hedging

Average realized crude oil prices for first quarter 2011 increased 31% as compared with first quarter 2010. Crude oil prices have been impacted by several factors during first quarter 2011, including political unrest in countries of the Middle East and Africa, as well as the earthquake and resulting tsunami in Japan.

Average realized natural gas prices for first quarter 2011 decreased 23% as compared with first quarter 2010 primarily due to domestic oversupply.

We have hedged approximately 50% of our expected global crude oil production and 59% of our expected domestic natural gas production for the remainder of 2011.

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OPERATING OUTLOOK

Our expected crude oil, natural gas and NGL production for 2011 may be impacted by several factors including:

- ongoing development activity in the Wattenberg Area and horizontal drilling in the Niobrara formation in the DJ Basin;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- natural field decline in the Deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and in the North Sea;
- potential legislative and regulatory changes on Deepwater Gulf of Mexico operating and safety standards for producing activities due to the 2010 explosion of the Deepwater Horizon drilling rig and subsequent oil spill (Deepwater Horizon Incident);
- 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;
- timing and performance of a compression project at the Mari-B field, offshore Israel;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the Deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Rocky Mountain area of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- potential purchases of producing properties;
- timing of significant project completion and initial production; and
- potential divestments of non-core, non-strategic operating assets.

2011 Capital Investment Program

Our total capital investment program for 2011 is estimated at $2.7 billion, with investment split relatively evenly between the US and international operations. Approximately 42% of the program is going toward major project developments, 18% for exploration and appraisal activities, and the remaining 40% for ongoing maintenance and near-term growth opportunities. Major project investments include our development activities in the Deepwater Gulf of Mexico, West Africa, Eastern Mediterranean, and our horizontal drilling program in the DJ Basin.

In addition to the capital investment program discussed above, we expect to accrue approximately $70 million for the Aseng FPSO lease obligation.

We expect that the 2011 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as our recent issuance of long-term debt. See Liquidity and Capital Resources.

We will evaluate the level of capital spending throughout the year based on the following factors, among others:

- commodity prices;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- permitting activity in the Deepwater Gulf of Mexico;
- potential changes in the fiscal regimes of the US and other countries in which we operate;
-

impact of implementation of the Dodd-Frank Act on our business practices, including, among others, requirements regarding the posting of cash collateral in hedging transactions;

- drilling results;
- property acquisitions and divestitures; and
- potential legislative or regulatory changes regarding the use of hydraulic fracturing.

Changes in Fiscal Regimes

Due to pressures from local constituents as well as the Organization for Economic Cooperation and Development to address negative fiscal situations and initiate deficit reduction measures, many governments are seeking additional revenue sources, including increases in government take from oil and gas projects. In many other countries, such as in the Middle East and Africa, increasing social demands are resulting in civil unrest. Future economic and political reforms in these countries could result in these governments also seeking additional revenue sources. During first quarter 2011, fiscal regime changes occurred in both Israel and the UK.

Israel – In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes a special levy on income from oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We currently expect these changes to increase our 2011 consolidated income tax expense by approximately $20 million and increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010. The impact of the changes in Israel's tax law is reflected in our balance sheet and results of operations at March 31, 2011.

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The change in Israel's fiscal regime may negatively impact our future operations by reducing future project profitability, as compared with profitability under the previous fiscal regime, and potentially reducing the economic attractiveness of exploration activities.

UK – Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas production in the UK from 20% to 32% effective March 24, 2011. We expect this change to become law later in 2011. We expect the change will increase the tax rate on our UK oil and gas income from 50% to 62%, resulting in an increase of approximately $50 million in our 2011 consolidated income tax expense and an increase in our 2011 consolidated effective income tax rate by approximately four percentage points. In addition, we must remeasure our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. These changes will be reflected in our balance sheet and results of operations when the Finance Bill 2011 is enacted, which we expect to occur second quarter 2011.

See Item 1. Financial Statements – Note 11. Income Taxes.

Impact of Japanese Earthquake and Tsunami

In March 2011, an earthquake and resulting tsunami struck Japan. Significant damage occurred and has resulted in disruptions in manufacturing, distribution and transportation activities. Japan is a significant manufacturer and distributer of steel products, including chrome-based steel tubular goods and other components used in oil and gas upstream activities, and export of some of these products is currently constrained. We are assessing the impacts of these disruptions on our major development projects offshore West Africa and Israel and believe we will be able to mitigate the impact of any disruption or delay in obtaining tubular goods or other products on our major development project timeline. However, we currently expect an increase in prices for certain components.

Risk and Insurance Program Update

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production), employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

For example, in certain international locations (including Equatorial Guinea and Israel) we carry business interruption insurance for loss of revenue arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In the Gulf of Mexico, we self-insure for windstorm exposure. This decision was made because past abandonment activities on the Gulf of Mexico shelf significantly reduced our windstorm exposure and our remaining Gulf of Mexico assets are primarily subsea operations. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. Therefore, we believe it is more cost-effective for us to self-insure these assets; therefore, we are responsible for substantially all windstorm-related damages to our Gulf of Mexico assets.

In accordance with industry practice, oil and gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our domestic and international drilling contracts contain such indemnification clauses. In addition, oil and gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $500 million of well control, pollution cleanup and consequential damages coverage and $326 million of additional pollution cleanup and consequential damages coverage, which also covers third party personal injury and death. Consequently, if we were to experience an accident similar to the Deepwater Horizon Incident, our total coverage for cleanup and consequential damages would be $826 million for our share, subject to reduction for claims related to well control and third party damages.

We expect the future availability and cost of insurance will be impacted by the recent earthquake and subsequent tsunami which occurred in Japan as well as by the Deepwater Horizon Incident. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We anticipate that current changes in the types of coverage available in the insurance market will result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

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During 2010, various Congressional committees began pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act may be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either a much higher level of insurance coverage than was standard for the industry in the past, or a financial position large enough that a company could settle its own damage claims. We anticipate that, at a minimum, less insurance coverage will be available and at a higher cost. We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and its impact on the insurance market and our overall risk profile. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Deepwater drilling entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a strong safety performance record and continue to manage our risks and operations such that the likelihood of a significant accident or spill is remote. However, if an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our results of operations, cash flows and financial condition.

Oil Spill Response Preparedness

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. On behalf of its membership, CGA has contracted with Helix Energy Solutions Group (Helix) for the provision of subsea intervention, containment, capture and shut-in capacity for Deepwater Gulf of Mexico exploration wells. The system, known as the Helix Fast Response System (HFRS), at full production capacity, can process up to 55 MBbl/d of oil, 70 MBbl/d of liquids and 95 MMcf/d of natural gas, at 10,000 psi in water depths to 8,000 feet. We have entered into a separate utilization agreement with Helix which specifies the asset day rates should the HFRS system be deployed.

RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase from Prior Year
(millions)			
Oil, Gas and NGL Sales	830	$688	21 %
Income from Equity Method Investees	48	26	85 %
Other Revenues	21	19	11 %
Total	$899	$733	23 %

Changes in revenues are discussed below.

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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 (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (PersMcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2011							
United States	37	382	14	114	$92.25	$4.07	$47.80
Equatorial Guinea (2)	13	248	-	55	103.49	0.27	-
Israel	-	140	-	23	-	4.19	-
North Sea	11	8	-	12	106.26	7.30	-
China	4	-	-	4	95.28	-	-
Total Consolidated Operations	65	778	14	208	97.15	2.91	47.80
Equity Investees (3)	2	-	5	7	103.93	-	75.71
Total Operations	67	778	19	215	$97.32	$2.91	$55.43
Three Months Ended March 31, 2010							
United States (4)	40	384	13	116	$73.80	$5.46	$44.98
Equatorial Guinea (2)	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 (3)	2	-	4	6	75.61	-	57.99
Total Operations	63	702	17	197	$74.16	$3.79	$48.00

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity price differentials, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

(2) 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.

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

(4) Average realized crude oil and condensate prices for first quarter 2010 reflect a reduction of $1.32 per Bbl from hedging activities.

Average realized natural gas prices for first quarter 2010 reflect a reduction of $0.03 per Mcf from hedging activities.

The price reductions resulted from hedge gains/losses that were previously deferred in AOCL. All hedge gains or losses relating to US production had been reclassified to revenues by December 31, 2010.

(5) Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales for 2010 were eliminated for accounting purposes. Electricity sales are included in other revenues.

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)			
	2011		2010	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended March 31,				
United States	$(2.75)	$0.76	$(0.52)	$0.02
Equatorial Guinea	-	-	(1.73)	-
Total Consolidated Operations	(1.56)	0.37	(0.58)	0.02
Total Operations	(1.52)	0.37	(0.56)	0.02

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	Natural Gas	NGLs	Total
Three Months Ended March 31, 2010	$407	$229	$52	$688
Changes due to				
Increase in Sales Volumes	27	36	3	66
Increase (Decrease) in Sales Prices Before Hedging	130	(63)	3	70
Change in Amounts Reclassified from AOCL	5	1	-	6
Three Months Ended March 31, 2011	$569	$203	$58	$830

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the first quarter of 2011 as compared with the first quarter of 2010 due to the following:

- a 31% increase in total consolidated average realized prices primarily due to concerns about impacts on the global crude oil supply caused by civil unrest in the nations of the Middle East and Africa and the recent weakness of the US dollar as compared to other international currencies;
- higher sales volumes in the DJ Basin attributable to ongoing development activity in the Wattenberg Area and horizontal drilling in the Niobrara formation;
- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010;
- higher sales volumes in Equatorial Guinea as compared with the first three months of 2010, during which time the Alba field was experiencing a planned shut-down for facilities maintenance and repair; and
- an increase in North Sea sales volumes primarily as a result of additional deliverability at the Dumbarton complex, including two Lochranza wells which began producing mid and late 2010;

partially offset by

- decreases in sales volumes from the Deepwater Gulf of Mexico, Gulf Coast and Mid-Continent Areas due to natural field decline;
- a decrease in onshore US volumes due to winter weather conditions; and
- a decrease in onshore US volumes due to the sale of certain Oklahoma assets and our Illinois Basin assets in 2010.

Revenues from crude oil and condensate sales for the first quarter of 2010 included deferred losses of $5 million reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to crude oil revenues.

Natural gas sales – Revenues from natural gas sales decreased during the first quarter of 2011 as compared with the first quarter of 2010 due to the following:

- a 23% decrease in total consolidated average realized prices (a 25% decrease in US average realized prices) primarily due to an abundant supply;
- a decrease in onshore US sales volumes due to winter weather conditions;
- a decrease in onshore US sales volumes due to the sale of certain Oklahoma assets and our Illinois Basin assets in 2010; and
-

decreases in sales volumes from the Deepwater Gulf of Mexico, Gulf Coast and Mid-Continent Areas due to natural field decline;

partially offset by:

- continued benefit of strong global liquids markets on natural gas prices in Israel;
- higher sales volumes in the DJ Basin attributable to ongoing vertical and horizontal drilling in the Wattenberg Area;
- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010;
- higher sales volumes in Equatorial Guinea as compared with the first three months of 2010, during which time the Alba field was experiencing a planned shut-down for facilities maintenance and repair;
- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by higher electricity production and lower levels of competitor natural gas imports from Egypt; and
- an increase in North Sea sales volumes primarily as a result of increased deliverability at the Dumbarton complex, including two Lochranza wells which began producing mid and late 2010.

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Revenues from natural gas sales for the first quarter of 2010 included a decrease of $1 million reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to natural gas revenues.

NGL sales – Most of our US NGL production is from the Wattenberg Area and Deepwater Gulf of Mexico. NGL sales revenues increased during the first quarter of 2011 as compared with 2010 due to a slight increase in sales volumes due to ongoing development activity and an 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 on Bioko Island 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 2011 as compared with 2010 was due to increases in average realized condensate, LPG and methanol prices due to global economic recovery, and increases in condensate and methanol sales volumes. 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 and prices were as follows:

	Three Months Ended March 31,	
	2011	2010
Methanol Sales Volumes (Mmgal)	40	35
Methanol Sales Prices	$1.03	$0.83

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,		Increase (Decrease) from Prior Year
	2011	2010	
(millions)			
Production Expense	$142	$139	2 %
Exploration Expense	70	80	(13 %)
Depreciation, Depletion and Amortization	221	216	2 %
General and Administrative	83	66	26 %
Other Operating (Income) Expense, Net	36	14	157 %
Total	$552	$515	7 %

Changes in operating costs and expenses are discussed below.

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Production Expense   Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate
Three Months Ended March 31, 2011							
Lease Operating Expense (2)	$ 4.89	$ 92	$ 62	$ 9	$ 3	$ 12	$ 6
Production and Ad Valorem Taxes	1.71	32	25	-	-	-	7
Transportation Expense	0.94	18	16	-	-	2	-
Total Production Expense	$ 7.54	$ 142	$ 103	$ 9	$ 3	$ 14	$ 13
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

(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 2011, total production expense increased as compared with 2010 due to the following:

- an increase in US lease operating expense due to higher sales volumes from the Wattenberg Area due to ongoing capital spending;
- increases in Equatorial Guinea, Israel, and North Sea lease operating expense due to higher sales volumes;
- an increase in China production taxes due to higher commodity prices; and
- an increase in US transportation expense due to higher crude oil and condensate production in the Wattenberg Area;

partially offset by:

- a decrease in US lease operating expense due to the sale of certain Oklahoma assets and our Illinois Basin assets in 2010; and
- a decrease in US production taxes due to lower crude oil sales volumes related to the sale of certain Oklahoma assets in 2010 and natural field decline in the Gulf Coast and Mid-Continent Areas.

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

(millions)	Total	United States	West Africa (1)	Eastern Mediterranean (2)	North Sea	Other Int'l, Corporate (3)
Three Months Ended March 31, 2011						
Dry Hole Cost	$22	$22	$-	$ -	$-	$-
Seismic	26	16	-	-	-	10
Staff Expense	18	5	1	-	-	12
Other	4	4	-	-	-	-
Total Exploration Expense	$70	$47	$1	$ -	$-	$22

Three Months Ended March 31, 2010						
Dry Hole Cost	$39	$36	$3	$ -	$-	$-
Seismic	22	22	-	-	-	-
Staff Expense	15	3	2	1	-	9
Other	4	4	-	-	-	-
Total Exploration Expense	$80	$65	$5	$ 1	$-	$9

(1) West Africa includes Equatorial Guinea and Cameroon.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other International includes China and various international new ventures.

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Oil and gas exploration expense for the first quarter of 2011 included the following:

- US dry hole cost associated with exploratory drilling in the Rocky Mountain area; and
- acquisition of seismic information for Wattenberg, Rocky Mountain and Deepwater Gulf of Mexico Areas in the US, offshore Nicaragua, and offshore France.

Oil and gas exploration expense for the first quarter of 2010 included the following:

- US dry hole cost associated with the Double Mountain exploration well in the Deepwater Gulf of Mexico; and
- acquisition of seismic information primarily in support of Central Gulf of Mexico lease sales.

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

	Three Months Ended March 31,	
	2011	2010
DD&A Expense (millions) (1)	$221	$216
Unit Rate per BOE (2)	$11.81	$12.57

(1) For DD&A expense by geographical area, see Item 1. Financial Statements – Note 13 Segment Information.
(2) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for the first quarter of 2011 increased as compared with 2010 due to the following:

- higher DD&A expense in the Wattenberg Area of our onshore US operations due to higher sales volumes resulting from ongoing capital spending;
- higher DD&A expense in Equatorial Guinea due to higher sales volumes;
- higher DD&A expense in the North Sea due to higher sales volumes and higher costs associated with development activities; and
- higher DD&A expense in China due to increased development activity;

partially offset by

- lower DD&A expense in the Piceance Basin area of our onshore US operations due to reserves additions at year end 2010 and lower sales volumes ;
- lower DD&A expense in the Deepwater Gulf of Mexico, Gulf Coast, and Mid-Continent Areas of our US operations due to lower sales volumes resulting from natural field decline; and
- the cessation of DD&A associated with certain Oklahoma assets and our Illinois Basin assets sold during 2010.

The unit rate per BOE decreased for the first quarter of 2011 as compared with 2010 due to the change in mix of production, including increases in lower-cost sales volumes from Equatorial Guinea and Israel and lower rates for the Piceance Basin.

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

	Three Months Ended March 31,	
	2011	2010
G&A Expense (millions)	$83	$66

Unit Rate per BOE (1)	$4.43	$3.86

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

G&A expense for the first quarter of 2011 increased as compared with 2010 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and exploration activities.

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Other Operating (Income) Expense, Net

Other operating (income) expense was as follows:

(millions)	Three Months Ended March 31, 2011	2010
Deepwater Gulf of Mexico Moratorium Expense	$18	$-
Electricity Generation Expense	17	10
Other, Net	1	4
Total	$36	$14

See Item 1. Financial Statements – Note 2. Basis of Presentation.

Other (Income) Expense

Other (income) expense was as follows:

(millions)	Three Months Ended March 31, 2011	2010
(Gain) Loss on Commodity Derivative Instruments	$286	$(145)
Interest, Net of Amount Capitalized	16	20
Other Non-Operating (Income) Expense, Net	8	-
Total	$310	$(125)

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments is a result of mark-to-market accounting. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities and Note 5. Fair Value Measurements and Disclosures.

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

(millions, except unit rate)	Three Months Ended March 31, 2011	2010
Interest Expense	$41	$35
Capitalized Interest	(25)	(15)
Interest Expense, Net	$16	$20
Unit Rate, per BOE (1)	$0.86	$1.15

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

Interest expense increased for the first quarter of 2011 as compared with 2010. The increase in interest expense resulted from a higher outstanding debt balance during the period and the interest associated with our recently-issued 6% senior unsecured notes. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility which was repaid with proceeds from our debt offering. See also Liquidity and Capital Resources – Financing Activities below.

The increase in the amount of interest capitalized is due to higher work in progress amounts related to major long-term projects in the Deepwater Gulf of Mexico, West Africa, and Israel and a higher weighted average interest rate associated with our recently-issued 6% senior unsecured notes, which impacted the average rate we pay on long-term debt, the rate we use to capitalize interest.

Other Non-operating (Income) Expense, Net   Other non-operating (income) expense, net includes deferred compensation expense, interest income and other (income) expense. The increase for the first quarter of 2011 was due to an $8 million increase in deferred compensation expense, as a result of a higher market value for our common stock as compared with first quarter 2010, and a $2 million increase in other (income) expense, net, offset by a $2 million increase in interest income. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Income Tax Provision

See Changes in Fiscal Regimes, above, and Item 1. Financial Statements – Note 11. Income Taxes for a discussion of the change in our effective tax rate during the first quarter of 2011 as compared with 2010.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our major development projects, we employ a capital structure and financing strategy designed to provide ample liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service 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 cash flows and operations.

Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under our credit facility. Occasional sales of non-strategic crude oil and natural gas properties as well as our periodic access to capital markets may also generate cash.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

Information regarding cash and debt balances was as follows:

(millions, except percentages)	March 31, 2011		December 31, 2010	
Cash and Cash Equivalents	$1,419		$1,081	
Amount Available to be Borrowed Under Credit Facility (1)	2,100		1,750	
Total Liquidity	$3,519		$2,831	
Total Debt (2)	$2,813		$2,279	
Total Shareholders' Equity	6,876		6,848	
Ratio of Debt-to-Book Capital (3)	29	%	25	%

(1) Our credit facility is committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion.
(2) Total debt includes FPSO lease obligation and excludes unamortized debt discount.
(3) 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 $1.4 billion in cash and cash equivalents at March 31, 2011, 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 programs, including the planned developments in Equatorial Guinea 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. We ended first quarter 2011 with $2.1 billion remaining available for borrowing under the current $2.1 billion commitment.

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, two and three-way 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. None of our counterparty agreements contain margin requirements. We 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.

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, 2011 the fair value of our commodity derivative assets was $2 million and the fair value of our commodity derivative liabilities was $319 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities for a discussion of counterparty credit risk and Note 5. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

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Contractual Obligations

In February 2011, we completed an underwritten public offering of $850 million, 6% senior unsecured notes due March 1, 2041. See Financing Activities below.

Based on the total debt balance, scheduled maturities and interest rates in effect at March 31, 2011, future long-term payments of principal (excluding our FPSO lease obligation) and interest are as follows:

Obligation (millions)	Total	2011	2012 and 2013	2014 and 2015	2016 and beyond
Long-Term Debt (1)	$2,484	$-	$-	$200	$2,284
Cash Payments for Interest	3,186	133	355	339	2,359

(1) Long-term debt excludes FPSO lease obligation.

Cash Flows

Cash flow information is as follows:

	Three Months Ended March 31,	
(millions)	2011	2010
Total Cash Provided By (Used in)		
Operating Activities	$484	$588
Investing Activities	(575)	(849)
Financing Activities	429	278
Increase in Cash and Cash Equivalents	$338	$17

Operating Activities Net cash provided by operating activities for the first three months of 2011 decreased as compared with the first three months of 2010. In first quarter 2011, increases in general and administrative expense, interest expense, and tax payments partially offset increases in cash flows resulting from higher sales volumes and crude oil prices. In addition, first quarter 2010 included a Deepwater Gulf of Mexico royalty relief refund of $84 million. See Item 1. Financial Statements – Consolidated Statements of Cash Flow.

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. Capital spending for property, plant and equipment increased by $195 million during the first three months of 2011 as compared with the first three months of 2010, primarily due to increased major project development activity in the Wattenberg Area, offshore Equatorial Guinea, and offshore Israel, and was offset by $3 million proceeds from the sale of non-core onshore US assets. Additional investing activities for 2010 included $466 million related to the Central DJ Basin asset acquisition.

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 2011, funds were provided by net cash proceeds from borrowings under our revolving credit facility ($120 million) and the issuance of 6% senior notes ($836 million). Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($31 million). We used a portion of the proceeds from the issuance of senior notes to repay amounts outstanding under our credit facility($470 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($32 million) and repurchase shares of our common stock ($16 million).

In comparison, 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 Central 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 repurchase shares of our common stock ($12 million).

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Investing Activities

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

	Three Months Ended March 31, 2011	2010
(millions)		
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition	$15	$146
Proved Property Acquisition	-	363
Exploration	122	115
Development	374	274
Corporate and Other	34	20
Total	$545	$918
Increase in FPSO Lease Obligation	$34	$40

2011Unproved property acquisition costs for the first three months of 2011 related to onshore US lease acquisitions. The increase in development costs is due to increased capital spending on major development projects located in the DJ Basin, offshore Equatorial Guinea and offshore Israel.

2010 Unproved and proved property acquisition costs for the first three months of 2010 related to the Central DJ Basin asset acquisition.

FPSO Lease Obligation   The FPSO lease obligation 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 3. Debt.

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 within the current $2.1 billion commitment 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.

In order to provide increased liquidity and lengthen our weighted average debt maturity, on February 18, 2011 we completed an underwritten public offering of $850 million of 6% senior unsecured notes due March 1, 2041, receiving net proceeds of $836 million after deducting discount and underwriting fees. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility maturing 2012 and the balance of the proceeds will be used for general corporate purposes.

At March 31, 2011, there were no borrowings outstanding under the credit facility, leaving the entire $2.1 billion available for use. We periodically borrow amounts under provision (ii) above for working capital purposes.

Our outstanding fixed-rate debt totaled almost $2.5 billion at March 31, 2011. The weighted average interest rate on fixed-rate debt was 7.14%, with maturities ranging from 2014 to 2097. Only 8% of our fixed rate debt matures within the next five years.

Our ratio of debt-to-book capital was 29% at March 31, 2011 as compared with 25% at December 31, 2010. 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.

Other 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, 2011 or December 31, 2010, nor did we borrow any funds under uncommitted credit lines during the first three months of 2011. 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 total cash dividends of 18 cents per share of our common stock during the first three months of each of 2011 and 2010. On April 25, 2011, our Board of Directors declared a quarterly cash dividend of 18 cents per common share, payable May 23, 2011 to shareholders of record on May 9, 2011. 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.

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Exercise of Stock Options   We received cash proceeds of $23 million from the exercise of stock options during the first three months of 2011 and $21 million from the exercise of stock options during the first three months of 2010.

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 178,499 shares with a value of $16 million during the first three months of 2011 and 161,447 shares with a value of $12 million during the first three months of 2010.

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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, 2011, 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 payable position with a fair value of $317 million. Based on the March 31, 2011 published commodity futures price strips for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative payable by approximately $24 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative payable by approximately $10 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 4. 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 the amount of interest we earn on our short-term investments.

At March 31, 2011, we had almost $2.5 billion (excluding the FPSO lease obligation and unamortized debt discount) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 7.14%. 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. See Item 8. Financial Statements and Supplementary Data – Note 5. Fair Value Measurements and Disclosures.

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, 2011, AOCL included $28 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified into earnings as adjustments to interest expense over the terms of our 5¼% Senior Notes due April 2014 and 6% Senior Notes due March 1, 2041. See Item 8. Financial Statements and Supplementary Data – Note 4. 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, 2011, our cash and cash equivalents totaled $1.4 billion, approximately 72% 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, 2011 would result in a change in annual interest income of approximately $3 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. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

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.

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.

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;

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- 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,” “believe,” “anticipate,” “estimate,” “intend,” and 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, 2010, 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, 2010 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 14. 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, 2010, other than the following:

Our operations require us to comply with a number of US and international laws and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business.

Our operations require us to comply with a wide variety of US and international laws and regulations, such as those involving anti-corruption, competition and antitrust, anti-boycott, export control and/or taxation.

For example, the US Foreign Corrupt Practices Act (FCPA) and similar laws and regulations enacted or promulgated by countries pursuant to the 1997 Organization for Economic Co-operation and Development Anti-Bribery Convention generally prohibit improper payments to foreign officials for the purpose of obtaining or keeping business. The scope and enforcement of anti-corruption laws and regulations may vary. The recently-enacted UK Bribery Act of 2010, which is scheduled to become effective in July 2011, is broader in scope than the FCPA and applies to public and private sector corruption and contains no facilitating payments exception. Violations of any such laws or regulations could result in substantial civil or criminal fines or sanctions. Actual or alleged violations could damage our reputation, be expensive to defend, and impair our ability to do business.

Mergers of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger. US antitrust laws require waiting periods and even after completion of a merger, governmental authorities could seek to block or challenge a merger as they deem necessary or desirable in the public interest. We have merged with or acquired other companies in the past. Prevention of a merger by antitrust laws could impair our ability to do business.

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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)
01/01/11 - 01/31/11	41,647	$ 85.56	-	-
02/01/11 - 02/28/11	132,991	90.40	-	-
03/01/11 - 03/31/11	3,861	92.88	-	-
Total	178,499	$ 89.33	-	-

(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 28, 2011	/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).
4.1	Second Supplemental Indenture dated as of February 18, 2011, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to senior debt securities of Noble Energy, Inc. (including the form of 2041 Notes) (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K (Date of Event: February 15, 2011) filed February 22, 2011 and incorporated herein by reference).
10.1	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 26, 2011), (filed as exhibit 10.1 to Registrant’s Current Report on Form 8-K (Date of Event: April 26, 2011) filed April 27, 2011 and incorporated herein by reference).
10.2	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. dated effective March 17, 2011 (filed as exhibit 10.1 to Registrant’s Current Report on Form 8-K (Date of Event: March 17, 2011) filed March 22, 2011 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.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

101.DEF	XBRL Definition Linkbase Document

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