

NOBLE ENERGY INC
Form 10-Q
April 30, 2009

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

FORM 10-Q

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

For the quarterly period ended March 31, 2009

OR

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

For the transition period from _____ to _____

Commission file number: 001-07964
NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware
(State of incorporation)

73-0785597
(I.R.S. employer identification number)

100 Glenborough Drive, Suite 100
Houston, Texas
(Address of principal executive offices)

77067
(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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

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Yes ☐ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

Number of shares of common stock outstanding as of April 13, 2009: 173,347,618.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended March 31,	
	2009	2008
Revenues		
Oil, gas and NGL sales	\$ 406	\$ 944
Income from equity method investees	11	62
Other revenues	24	19
Total	441	1,025
Costs and Expenses		
Lease operating expense	100	82
Production and ad valorem taxes	18	43
Transportation expense	12	13
Exploration expense	42	40
Depreciation, depletion and amortization	200	203
General and administrative	59	60
Asset impairments	437	-
Other operating (income) expense, net	(6)	27
Total	862	468
Operating Income (Loss)	(421)	557
Other (Income) Expense		
(Gain) loss on commodity derivative instruments	(73)	237
Interest, net of amount capitalized	18	17
Other (income) expense, net	8	(13)
Total	(47)	241
Income (Loss) Before Income Taxes	(374)	316
Income Tax Provision (Benefit)	(186)	101
Net Income (Loss)	\$ (188)	\$ 215
Earnings (Loss) Per Share		
Basic	\$ (1.09)	\$ 1.25
Diluted	(1.09)	1.20
Weighted average number of shares outstanding		
Basic	173	172
Diluted	173	175

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

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

	(unaudited) March 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 1,017	\$ 1,140
Accounts receivable, net	493	423
Commodity derivative instruments	403	437
Other current assets	134	158
Total current assets	2,047	2,158
Property, plant and equipment		
Oil and gas properties (successful efforts method of accounting)	11,921	11,963
Other property, plant and equipment	176	175
Total property, plant and equipment	12,097	12,138
Accumulated depreciation, depletion and amortization	(3,328)	(3,134)
Total property, plant and equipment, net	8,769	9,004
Goodwill	757	759
Other noncurrent assets	469	463
Total Assets	\$ 12,042	\$ 12,384
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable - trade	\$ 509	\$ 579
Income taxes payable	165	130
Deferred income taxes	121	142
Other current liabilities	354	323
Total current liabilities	1,149	1,174
Long-term debt	2,357	2,241
Deferred income taxes	1,901	2,174
Other noncurrent liabilities	510	486
Total Liabilities	5,917	6,075
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock - par value \$1.00; 4 million shares authorized, none issued	-	-
Common stock - par value \$3.33 1/3; 250 million shares authorized; 193 million and 192 million shares issued, respectively	645	641
Capital in excess of par value	2,215	2,193

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Accumulated other comprehensive loss	(100)	(110)
Treasury stock, at cost; 19 million shares	(615)	(614)
Retained earnings	3,980	4,199
Total Shareholders' Equity	6,125	6,309
Total Liabilities and Shareholders' Equity	\$ 12,042	\$ 12,384

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

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

	Three Months Ended March 31,	
	2009	2008
Cash Flows From Operating Activities		
Net income (loss)	\$ (188)	\$ 215
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	200	203
Asset impairments	437	-
Deferred income taxes	(301)	35
Income from equity method investees	(11)	(62)
Dividends from equity method investees	-	76
Unrealized loss on commodity derivative instruments	80	218
Settlement of previously recognized hedge losses	-	(62)
Allowance for doubtful accounts	(40)	3
Other	24	17
Changes in operating assets and liabilities:		
(Increase) in accounts receivable	(34)	(137)
(Increase) in other current assets	(1)	(5)
(Decrease) in accounts payable	(35)	(61)
Increase in other current liabilities	54	66
Net Cash Provided by Operating Activities	185	506
Cash Flows From Investing Activities		
Additions to property, plant and equipment	(399)	(464)
Proceeds from sale of property, plant and equipment	-	109
Net Cash Used in Investing Activities	(399)	(355)
Cash Flows From Financing Activities		
Exercise of stock options	11	10
Excess tax benefits from stock-based awards	3	9
Cash dividends paid	(31)	(21)
Purchase of treasury stock	(1)	(2)
Proceeds from credit facilities	180	200
Repayment of credit facilities	(1,060)	(200)
Proceeds from issuance of 8 1/4% senior notes	989	-
Net Cash Provided by (Used in) Financing Activities	91	(4)
(Decrease) Increase in Cash and Cash Equivalents	(123)	147
Cash and Cash Equivalents at Beginning of Period	1,140	660
Cash and Cash Equivalents at End of Period	\$ 1,017	\$ 807

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

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

Three Months Ended
March 31,
2009 2008

Common Stock

Balance, beginning of period	\$ 641	\$ 636
Exercise of stock options	2	2
Restricted stock awards, net	2	1
Balance, end of period	645	639
Capital in Excess of Par Value		
Balance, beginning of period	2,193	2,106
Stock-based compensation expense	12	9
Exercise of stock options	9	8
Tax benefits related to exercise of stock options	3	9
Restricted stock awards, net	(2)	(1)
Rabbi trust shares sold	-	2
Balance, end of period	2,215	2,133
Accumulated Other Comprehensive Loss		
Balance, beginning of period	(110)	(284)
Oil and gas cash flow hedges:		
Realized amounts reclassified into earnings	11	38
Interest rate cash flow hedges:		
Unrealized change in fair value	-	(27)
Net change in other	(1)	(1)
Balance, end of period	(100)	(274)
Treasury Stock at Cost		
Balance, beginning of period	(614)	(613)
Purchases of treasury stock	(1)	(2)
Rabbi trust shares sold	-	2
Balance, end of period	(615)	(613)
Retained Earnings		
Balance, beginning of period	4,199	2,964
Net income (loss)	(188)	215
Cash dividends (\$0.18 per share and \$0.12 per share, respectively)	(31)	(21)
Balance, end of period	3,980	3,158
Total Shareholders' Equity	\$ 6,125	\$ 5,043

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1 – Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is an independent energy company engaged in worldwide crude oil, natural gas and natural gas liquids (NGL) acquisition, exploration and production. We operate primarily in the Rocky Mountains, Mid-continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel, the North Sea and 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 for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US generally accepted accounting principles (GAAP) for complete financial statements. The accompanying consolidated financial statements at March 31, 2009 (unaudited) and December 31, 2008 and for the three months ended March 31, 2009 and 2008 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the three-month period ended March 31, 2009 are not necessarily indicative of the results that may be expected for the year ended December 31, 2009. 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, 2008.

Estimates – The preparation of consolidated financial statements in conformity with GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Current credit market conditions combined with volatile commodity prices have resulted in increased uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined accurately, actual results could differ significantly from our estimates.

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

	Three Months Ended March 31, 2009 2008 (in millions)	
Other Revenues		
Electricity sales (1)	\$ 20	\$ 15
Gathering, marketing and processing (GMP) revenues	4	4
Total	\$ 24	\$ 19
Other Operating (Income) Expense, net		
Electricity generation expense (1)	\$ (30)	\$ 15
Gathering, marketing and processing (GMP) expense	6	5
Other operating expense, net	18	7
Total	\$ (6)	\$ 27
Other (Income) Expense, net		
Deferred compensation expense (income)	\$ 5	\$ (7)
Interest income	-	(6)
Other expense, net	3	-

Total	\$	8	\$	(13)
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(1) Includes amounts related to our 100%-owned Ecuador integrated power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel the Machala power plant located in Machala, Ecuador. Electricity generation expense includes depreciation, depletion and amortization expense (DD&A) and changes in the allowance for doubtful accounts. We recognized a net decrease of \$42 million in the Ecuador allowance during first quarter 2009 and a net increase of \$3 million during first quarter 2008. See Allowance for Doubtful Accounts below.

Balance Sheet Information – Other balance sheet information is as follows:

	March 31, 2009	December 31, 2008
	(in millions)	
Other Current Assets		
Inventories	\$ 116	\$ 105
Asset held for sale (1)	-	26
Prepaid expenses and other current assets	18	27
Total	\$ 134	\$ 158
Other Noncurrent Assets		
Equity method investments	\$ 323	\$ 311
Mutual fund investments	77	84
Commodity derivative instruments	24	33
Other noncurrent assets	45	35
Total	\$ 469	\$ 463
Other Current Liabilities		
Accrued and other current liabilities	\$ 202	\$ 215
Commodity derivative instruments	34	23
Short-term borrowings	25	25
Asset retirement obligations	44	27
Interest payable	25	9
Deferred gain on asset sale	24	24
Total	\$ 354	\$ 323
Other Noncurrent Liabilities		
Deferred compensation liabilities	\$ 164	\$ 159
Asset retirement obligations	185	184
Accrued benefit costs	83	81
Commodity derivative instruments	12	2
Other noncurrent liabilities	66	60
Total	\$ 510	\$ 486

(1) See Asset Held for Sale below.

Asset Held for Sale – During 2008, we initiated a process to sell our remaining operated non-core Gulf of Mexico shelf asset located at Main Pass. Numerous parties expressed an interest in purchasing the asset. However, due to difficulties in obtaining appropriate insurance, bonding or financing, none of the potential buyers were able to close on the sale. As a result, we believe it is no longer probable that a sale of the asset will be completed within one year of its classification as held-for-sale. Therefore, the asset has been reclassified as held-and-used. Due to significant increases in insurance costs and exposure to further windstorm damage, our current plans are to abandon the Main Pass asset,

and therefore this property was impaired. See Note 5 – Fair Value Measurements.

Allowance for Doubtful Accounts – Through December 31, 2008, we had recorded an allowance for doubtful accounts of \$57 million related to our Ecuador power operations. The allowance was necessary to cover potentially uncollectible balances, as certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. As a result of pursuing various strategies to protect our interests, including international arbitration and litigation, we reached a settlement in fourth quarter 2008. In March and April 2009, we received total payments of \$60 million in accordance with the terms of the settlement, against which a reserve of \$46 million had previously been recorded. Accordingly, we reduced the allowance for doubtful accounts by \$46 million and included the amount as a reduction in electricity generation expense. We recorded an additional allowance of \$6 million related to current period commodity and electricity sales.

Adoption of FSP SFAS 132(R) – In December 2008, the FASB issued FSP SFAS 132(R), “Employers’ Disclosures About Postretirement Benefit Plan Assets” (FSP SFAS 132(R)). FSP SFAS 132(R) requires employers to make additional disclosures about plan assets for defined benefit pension and other postretirement benefit plans beginning with annual periods ending after December 15, 2009. The requirements apply to entities that are subject to the disclosure requirements of SFAS 132(R). Disclosures are to provide an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair-value measurements using significant unobservable inputs on changes in plan assets for the period, and significant concentrations of risk within plan assets. We adopted FSP SFAS 132(R) as of January 1, 2009. The statement provides only for enhanced annual disclosures and does not require additional interim disclosures. Adoption had no impact on our financial position or results of operations.

Adoption of SFAS 141(R) and SFAS 160 – In 2007, the FASB issued SFAS No. 141(R), “Business Combinations” (SFAS 141(R)) and SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements” (SFAS 160). These statements require most identifiable assets, liabilities and noncontrolling interests to be recorded at full fair value and require noncontrolling interests to be reported as a component of equity. Both statements are effective for periods beginning on or after December 15, 2008. SFAS 141(R) will be applied to business combinations occurring after the effective date and SFAS 160 will be applied prospectively to all noncontrolling interests, including any that arose before the effective date. We adopted SFAS 141(R) and SFAS 160 as of January 1, 2009. There were no non-controlling interests at adoption date. Adoption had no effect on our financial position or results of operations.

Adoption of SFAS 157 – SFAS No. 157, “Fair Value Measurements” (SFAS 157) establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. As of January 1, 2008, we adopted the provisions of SFAS 157 related to our financial assets and liabilities. As of January 1, 2009, we adopted the provisions of SFAS 157 related to our nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. Adoption of SFAS 157 did not have a significant impact on our consolidated financial statements. See Note 5 – Fair Value Measurements. See also Note 16 – Recently Issued Pronouncements.

Adoption of SFAS 161 – In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161). SFAS 161 amends and expands the disclosure requirements of SFAS 133, “Accounting for Derivative Instruments and Hedging Activities”, and requires qualitative disclosures about objectives and strategies for using derivative instruments, quantitative disclosures about fair value amounts of derivative instruments and related gains and losses, and disclosures about credit risk-related contingent features in derivative agreements. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS 161 as of January 1, 2009. The statement provides only for enhanced disclosures. Therefore, adoption had no impact on our financial position or results of operations. See Note 4 – Derivative Instruments and Hedging Activities.

Adoption of EITF 08-06 – In November 2008, the FASB ratified the consensus reached in EITF 08-06, “Equity Method Investment Accounting Considerations” (EITF 08-06). EITF 08-06 was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of SFAS 141(R). EITF 08-06 concluded that equity method investments should continue to be recognized using a cost accumulation model, thus continuing to include transaction costs in the carrying amount of the equity method investment. In addition, EITF 08-06 clarifies that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. EITF 08-06 is effective for fiscal years beginning on or after December 15, 2008. We adopted EITF 08-06 as of January 1, 2009. Adoption had no effect on our financial position or results of

operations.

Note 3 – Debt Issuance

On February 27, 2009, we closed an offering of \$1 billion senior unsecured notes receiving net proceeds of \$989 million, after deducting the discount and underwriting fees. The notes are due March 1, 2019, and pay interest semi-annually at 8¼%. Debt issuance costs of approximately \$2 million were incurred and are being amortized to expense over the life of the debt issue. Substantially all of the net proceeds from the offering were used to repay outstanding indebtedness under our revolving credit facility maturing 2012. 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.

Our debt consists of the following:

	March 31, 2009		December 31, 2008	
	Debt	Interest Rate	Debt	Interest Rate
	(in millions, except percentages)			
Credit facility	\$ 726	0.81%	\$ 1,606	0.80%
5 ¼% Senior Notes, due April 15, 2014	200	5.25%	200	5.25%
8 ¼% Senior Notes, due March 1, 2019	1,000	8.25%	-	-
7 ¼% Notes, due October 15, 2023	100	7.25%	100	7.25%
8% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
7 ¼% Senior Debentures, due August 1, 2097	89	7.25%	89	7.25%
Long-term debt	2,365		2,245	
Installment payments, due May 11, 2009	25	1.76%	25	4.18%
Total debt	2,390		2,270	
Unamortized discount	(8)		(4)	
Total debt, net of discount	\$ 2,382		\$ 2,266	

Note 4 – Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments – We are exposed to certain risks relating to our ongoing business operations. The primary risk managed by using derivative instruments is commodity price risk. We use various commodity derivative instruments in connection with forecasted crude oil and natural gas sales to minimize the impact of commodity price fluctuations. Such instruments include variable to fixed price swaps, collars and basis swaps.

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

We account for derivative instruments and hedging activities in accordance with SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended, and all derivative instruments are reflected as either assets or liabilities at fair value in our consolidated balance sheets. See Note 5 – Fair Value Measurements for a discussion of methods and assumptions used to estimate the fair values of our commodity derivative instruments and gross amounts of commodity derivative assets and liabilities.

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of financial institutions, a majority of which are lenders under our credit facility arrangement. Certain of these financial institutions have received capital injections and other forms of support from government sources, and may require additional financial assistance in the future to remain viable. Discontinuance of government support to these institutions could have an adverse impact on the collectibility of our derivative receivables. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties’ creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to

mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices as well as incur a loss. See also Note 5 – Fair Value Measurements.

Commodity Derivative Instruments – During 2009 and 2008 we accounted for our commodity derivative instruments using mark-to-market accounting, and we recognize all gains and losses on such instruments in earnings during the period in which they occur. Prior to January 1, 2008, we elected to designate certain of our commodity derivative instruments as cash flow hedges. Net derivative gains and losses that were deferred in accumulated other comprehensive loss (AOCL) as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur. See Derivatives in SFAS 133 Cash Flow Hedging Relationships table below.

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As of March 31, 2009, we had entered into the following crude oil derivative instruments:

Variable to Fixed Price Swaps				Collars			
Production		Bbls	Weighted Average		Bbls	Weighted Average Floor Price	Weighted Average Ceiling Price
Period	Index	Per Day	Fixed Price	Index	Per Day		
2009	NYMEX WTI	9,000	\$ 88.43	NYMEX WTI	6,700	\$ 79.70	\$ 90.60
2009	Dated Brent	2,000	87.98	Dated Brent	5,074	70.62	87.93
2009 Average		11,000	88.35		11,774	75.79	89.45
2010				NYMEX WTI	10,500	61.10	76.73

From April 1, 2009 to April 17, 2009, we entered into additional NYMEX WTI collars covering 3,000 Bbls per day for calendar year 2010 with weighted average floor and ceiling prices of \$60.00 and \$70.00, respectively.

As of March 31, 2009, we had entered into the following natural gas derivative instruments:

Collars				
Production Period	Index	MMBtu Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2009	NYMEX HH	170,000	\$ 9.15	\$ 10.81
2009	IFERC CIG (1)	15,000	6.00	9.90
2009 Average		185,000	8.90	10.73
2010	NYMEX HH	40,000	5.88	6.50
2010	IFERC CIG	15,000	6.25	8.10
2010 Average		55,000	5.98	6.94

(1) Colorado Interstate Gas – Northern System

From April 1, 2009 to April 17, 2009, we entered into additional NYMEX HH collars covering 80,000 MMBtu per day for calendar year 2010 with weighted average floor and ceiling prices of \$5.81 and \$6.83, respectively. We also entered into additional NYMEX HH collars covering 60,000 MMBtu per day for calendar year 2011 with weighted average floor and ceiling prices of \$5.83 and \$6.94, respectively.

As of March 31, 2009, we had entered into the following natural gas basis swaps:

Basis Swaps				
Production Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2009			140,000	\$ (2.49)

	IFERC CIG	NYMEX HH		
2010	IFERC CIG	NYMEX HH	80,000	(1.77)

From April 1, 2009 to April 17, 2009, we did not enter into any additional basis swaps.

Interest Rate Derivative Instruments – Changes in fair value of interest rate swaps or interest rate “locks” designated as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. During first quarter 2008, we had two interest rate swaps, or interest rate “locks”, each in the notional amount of \$500 million. The locks were based on five and ten year US Treasury rates of 3.55% and 4.15%, respectively, and were scheduled to expire in September 2008. The locks were designated as cash flow hedges and changes in their fair values of \$27 million, net of tax, were reported as losses in AOCL during first quarter 2008. The locks were settled in July 2008 at a cost of \$0.2 million.

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

Derivative Instruments Not Designated as Hedging Instruments Under SFAS 133

(in millions)	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2009		December 31, 2008		March 31, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity derivative instruments								
	Current assets	\$ 403	Current assets	\$ 437	Current liabilities	\$ 34	Current liabilities	\$ 23
	Noncurrent assets	24	Noncurrent assets	33	Noncurrent liabilities	12	Noncurrent liabilities	2
Total		\$ 427		\$ 470		\$ 46		\$ 25

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

Derivative Instruments Not Designated as Hedging Instruments Under SFAS 133

	Location of (Gain) Loss Recognized in Income on Derivative Instrument		Amount of (Gain) Loss Recognized in Income on Derivative Instrument Three Months Ended March 31,	
			2009	2008
			(in millions)	
Commodity derivative instruments	(Gain) loss on commodity derivative instruments			
Realized mark-to-market (gain) loss			\$ (153)	\$ 19
Unrealized mark-to-market loss	(Gain) loss on commodity derivative instruments		80	218
Total			\$ (73)	\$ 237

Derivative Instruments in Previously Designated SFAS 133 Cash Flow Hedging Relationships

	Location of (Gain) Loss Reclassified	Amount of (Gain) Loss
Amount of (Gain) Loss Recognized in OCI on Derivative Instrument	from AOCL into Income	Reclassified from AOCL on Derivative Instrument

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	Three Months Ended March 31, 20092008 (in millions)					Three Months Ended March 31, 20092008 (in millions)			
Commodity derivative instruments (1)									
Crude oil	\$	-	\$	-	Oil, gas and NGL sales	\$	17	\$	97
Natural gas		-		-	Oil, gas and NGL sales		-		(37)
Treasury rate locks		-		43	-		-		-
Total	\$	-	\$	43		\$	17	\$	60

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

AOCL – As of March 31, 2009, the balance in AOCL included net deferred losses of \$38 million related to the fair value of commodity derivative instruments previously accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefits of \$23 million. Approximately \$29 million of deferred losses (net of tax) related to the fair values of the commodity derivative instruments previously designated as cash flow hedges and remaining in AOCL at March 31, 2009 will be reclassified to earnings during the next 12 months as the forecasted transactions occur, and will be recorded as a reduction in oil and gas sales of approximately \$46 million before tax. All forecasted transactions currently being hedged and for which amounts remain in AOCL at March 31, 2008, are expected to occur by December 2010.

Note 5 – Fair Value Measurements

SFAS 157 establishes a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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.

Commodity Derivative Instruments – Our commodity derivative instruments consist of variable to fixed price commodity swaps, collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves for the underlying commodities as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters. See Note 4 – Derivative Instruments and Hedging Activities.

Deferred Compensation Liability - The value is dependant upon the fair values of mutual fund investments and shares of Noble Energy 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					
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)		Adjustmen	Fair Value
				(in millions)	(1)	Measurement
As of March 31, 2009						
Financial assets:						
Mutual fund investments	\$ 77	\$ -	\$ -		\$ -	\$ 77
Commodity derivative instruments	-	445	-		)	427
Financial liabilities:						
Commodity derivative instruments	-	(64)	-		18	(46)
Liability under Patina deferred compensation plan	(122)	-	-		-	(122)
As of December 31, 2008						
Financial assets:						
Mutual fund investments	84	-	-		-	84
Commodity derivative instruments	-	492	-		)	470
Financial liabilities:						
Commodity derivative instruments	-	(47)	-		22	(25)
Liability under Patina deferred compensation plan	(123)	-	-		-	(123)

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

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments – In accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” we review a proved oil and gas property for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. We estimate the future cash flows expected in connection with the property and compare such future cash flows to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management’s expectations for the future and include estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

As a result of a significant decline in the forward natural gas futures price strip at March 31, 2009, we reviewed our oil and gas properties that are sensitive to natural gas price decreases for impairment. We determined that the carrying amount of Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, was not recoverable from future cash flows and, therefore, was impaired at March 31, 2009. We reduced Granite Wash to its fair value, which was determined using the discounted cash flow method described above, as comparable market data was not available. We also impaired the Main Pass asset which had been reclassified from held-for-sale to held-and-used. Total pre-tax (non-cash) impairments for first quarter 2009 were \$437 million. The impaired assets, which had a total carrying amount of \$753 million, were reduced to their estimated fair value of \$316 million. See also Note 2 – Basis of Presentation – Asset Held for Sale.

Asset Retirement Obligations – We estimate the fair values of asset retirement obligations (AROs) based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 7 – Asset Retirement Obligations for a summary of changes in AROs.

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

Description	Fair Value Measurement	Fair Value Measurements Using			Total Impairment Loss
		Quoted Prices in Active Markets (Level 1)	Other	Significant	
			Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	
Three Months Ended March 31, 2009					
Impaired US oil and gas properties	\$ 316	-	\$ 316	-	\$ (437)
Asset retirement obligations incurred in current period	1	-	-	1	-
Three Months Ended March 31, 2008					
Asset retirement obligations incurred in current period	14	-	-	14	-

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:

	Three Months Ended March 31, 2009 (in millions)
Capitalized exploratory well costs, beginning of period	\$ 501
Additions to capitalized exploratory well costs pending determination of proved reserves	68
Reclassified to property, plant and equipment based on determination of proved reserves	(88)
Capitalized exploratory well costs charged to expense	(4)
Capitalized exploratory well costs, end of period	\$ 477

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:

	March 31, 2009	December 31, 2008
	(in millions)	
Exploratory well costs capitalized for a period of one year or less	\$ 255	\$ 256
Exploratory well costs capitalized for a period greater than one year after completion of drilling	222	245
Balance at end of period	\$ 477	\$ 501

Number of projects with exploratory well costs that have been capitalized for a period greater than one year after completion of drilling 4 6

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, 2009:

Project	Total	Suspended Since			2006 & Prior
		2008 (in millions)	2007		
West Africa	\$ 168	\$ 8	\$ 140	\$ 20	
Redrock (deepwater Gulf of Mexico)	17	-	-	17	
Flyndre (North Sea)	15	-	12	3	
Selkirk (North Sea)	22	-	22	-	
Total exploratory well costs capitalized for a period greater than one year after completion of drilling	\$ 222	\$ 9	\$ 174	\$ 40	

West Africa – The West Africa project includes Blocks O and I offshore Equatorial Guinea and the YoYo concession offshore Cameroon. Since drilling the initial well for this project, additional seismic work has been completed and exploration and appraisal wells have been drilled to further evaluate our discoveries. The West Africa development team is proceeding with a program to further define the resources in this area such that an optimal development program may be designed. Accordingly, a development plan for the Benita discovery on Block I was submitted to the Equatorial Guinean government in December 2008, and we await its approval. In addition to the exploratory well costs that have been capitalized for a period greater than one year for the West Africa project, we have incurred \$113 million in suspended costs related to additional drilling activity in West Africa through March 31, 2009.

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 to the completed sidetrack well at Raton South (Mississippi Canyon Block 292). Tie-back of Redrock is anticipated to occur following the tie-back of Raton South.

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

Selkirk (North Sea) – The Selkirk project is also located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an appraisal well which was then sidetracked to the original discovery well location, to ensure presence of effective reservoir, and suspended as a future producer. We are currently working with our non-operating partners on an alternative host and with the supply chain to reduce costs.

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. See Note 5 – Fair Value Measurements for a discussion of the methods and assumptions used to estimate the fair values of asset retirement obligations. Changes in asset retirement obligations were as follows:

	Three Months Ended March 31, 2009 2008 (in millions)	
Asset retirement obligations, beginning of period	\$ 211	\$ 144
Liabilities incurred in current period	1	14
Liabilities settled in current period	(2)	(4)
Revisions	16	3
Accretion expense	3	2
Asset retirement obligations, end of period	\$ 229	\$ 159

Revisions relate primarily to our remaining Main Pass asset. 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, 2009 2008 (in millions)	
Service cost	\$ 3	\$ 3
Interest cost	3	3
Expected return on plan assets	(3)	(3)
Other	1	-
Net periodic benefit cost	\$ 4	\$ 3

Note 9 – Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended March 31, 2009 2008 (in millions)	
Stock-based compensation expense	\$ 12	\$ 9
Tax benefit recognized	(4)	(3)

During the three months ended March 31, 2009, we granted 1.5 million stock options with a weighted-average grant-date fair value of \$18.75 per share and awarded 0.6 million shares of restricted stock subject to service conditions with a weighted-average grant-date fair value of \$50.21 per share. In 2009, we began making grants of restricted stock under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan that time-vest 20% after year one, an additional 30% after year two and the remaining 50% after year three.

Note 10 – Basic and Diluted Earnings (Loss) Per Share

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

	Three Months Ended March 31, 2009 2008			
	Net (Loss)	Weighted Average Shares	Net Income	Weighted Average Shares
	(in millions, except per share amounts)			
Net income (loss)	\$ (188)	173	\$ 215	172
Basic Earnings (Loss) Per Share	\$ (1.09)		\$ 1.25	
Net income (loss)	\$ (188)	173	\$ 215	172

Plus incremental shares from assumed conversions:

Dilutive options, restricted stock awards and shares of common stock in rabbi trust		-	-	(4)	3
Net income (loss) available to common shareholders	\$	(188)	173	\$	211
Diluted Earnings (Loss) Per Share	\$	(1.09)		\$	1.20

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

A total of 4.6 million weighted average stock options, restricted shares and common shares held in a rabbi trust were antidilutive for first quarter 2009 and were excluded from the calculation of diluted earnings per share. A total of 1.2 million weighted average stock options and restricted shares were antidilutive for first quarter 2008 and were excluded from the calculation of diluted earnings per share.

Note 11 – Income Taxes

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

	Three Months Ended March 31, 2009 2008 (in millions)	
Current	\$ 115	\$ 66
Deferred	(301)	35
Total income tax provision (benefit)	\$ (186)	\$ 101

The deferred tax benefit for the three months ended March 31, 2009 was due primarily to the fact that most of the deferred tax liability recorded in 2008 with respect to unrealized mark-to-market gains reverses in 2009. In addition, we recorded a deferred tax asset with respect to impairment losses on our US oil and gas properties.

Our effective tax rate increased to 50% for first quarter 2009 as compared with 32% for first quarter 2008 due primarily to the fact that the 2009 rate represents a tax benefit divided by a pre-tax loss. In that case, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate.

During first quarter 2009, we repatriated \$180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US current tax expense by \$11 million. In addition, we reversed a \$9 million US deferred tax liability that had been recorded in 2008 with respect to the repatriated earnings. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

Unrecognized Tax Positions – We do not have significant unrecognized tax benefits as of March 31, 2009. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. We did not accrue interest or penalties at March 31, 2009, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax, and we believe that we are below the minimum statutory threshold for imposition of penalties.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2005, Equatorial Guinea – 2006, China – 2006, Israel – 2000, UK – 2006 and the Netherlands – 2005.

Note 12 – Comprehensive Income (Loss)

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

	Three Months Ended March 31, 2009 2008 (in millions)	
Net income (loss)	\$	(188) \$ 215
Other items of comprehensive income (loss)		
Oil and gas cash flow hedges		
Realized amounts reclassified into earnings		17 60
Less tax provision		(6) (22)
Interest rate cash flow hedges		
Unrealized change in fair value		- (43)
Less tax provision		- 16
Net change in other		(1) (1)
Other comprehensive income		10 10
Comprehensive income (loss)	\$	(178) \$ 225

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 acquisition, exploration and production: the United States; West Africa; the North Sea; Israel; and Other International, Corporate and Marketing. Other International includes primarily Argentina (through February 2008), China, Ecuador and Suriname. The following data was prepared on the same basis as our consolidated financial statements and excludes the effects of income taxes.

	Consolidated	United States	West Africa	North Sea	Israel	Other Int'l, Corporate, Marketing
(in millions)						
Three Months Ended March 31, 2009						
Revenues from third parties	\$ 447	\$ 237	\$ 58	\$ 34	\$ 28	\$ 90
Reclassification from AOCL (1)	(17)	(9)	(8)	-	-	-
Intersegment revenue	-	52	-	-	-	(52)
Income from equity method investees	11	-	11	-	-	-
Total Revenues	441	280	61	34	28	38
DD&A	200	169	9	9	5	8
Asset impairments	437	437	-	-	-	-
Gain on commodity derivative instruments	(73)	(67)	(6)	-	-	-
Income (loss) before income taxes	(374)	(409)	42	11	21	(39)

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Three Months Ended March 31,
2008

Revenues from third parties	1,023	\$	577	\$	141	\$	92	\$	40	\$	173	
Reclassification from AOCL (1)	(60)		(48)		(12)		-		-		-	
Intersegment revenue	-		116		-		-		-		(116)	
Income from equity method investees	62		-		62		-		-		-	
Total Revenues	1,025		645		191		92		40		57	
DD&A	203		164		9		16		6		8	
Loss on commodity derivative instruments	237		209		28		-		-		-	
Income (loss) before income taxes	316		145		150		55		31		(65)	
Total assets at March 31, 2009 (2)	\$	12,042	\$	9,008	\$	1,590	\$	581	\$	407	\$	456
Total assets at December 31, 2008 (2)		12,384		9,212		1,614		775		366		417

(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.

(2) The US reporting unit includes goodwill of \$757 million at March 31, 2009 and \$759 million at December 31, 2008.

Note 14 – Commitments and Contingencies

Purchaser Bankruptcy – We have an exposure from crude oil sales for the months of June and July 2008 to SemCrude, L.P. (SemCrude), a subsidiary of SemGroup, L.P. (SemGroup). On July 22, 2008, SemGroup, including SemCrude, filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code under Case Number 08-11525 (BLS) in the United States Bankruptcy Court for the District of Delaware.

We have a receivable of approximately \$70 million from SemCrude. During 2008, we determined that it was probable that a portion of the receivable was uncollectible and reduced the carrying value of the SemCrude receivable by \$38 million for the probable loss. We are pursuing various legal remedies to protect our interests. We believe that ultimate disposition of this matter will not have a material adverse effect on our financial position, results of operations, or cash flows.

Legal Proceedings – We are among a group of 18 defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930's. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. Dore has delivered documents alleging approximately \$140 million in damages. Dore has obtained judgment or settlement with certain defendants, and trial involving Dore's claims against us, which began on April 27, 2009, and is ongoing. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our financial position, results of operations, or cash flows.

We are involved in various other 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.

Note 15 – Recently Issued Pronouncements

Recent FASB Staff Positions – In April 2009, the FASB issued three related staff positions to clarify the application of SFAS 157 to fair value measurements in the current economic environment, modify the recognition of other-than-temporary impairments of debt securities, and require companies to disclose the fair value of financial instruments in interim periods. The final staff positions are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009, if all three staff positions or both the fair value measurements and other-than-temporary impairment staff positions are adopted simultaneously.

- **FSP SFAS 157-4** – FASB Staff Position No. 157-4, “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability has Significantly Decreased and Identifying Transactions That Are Not Orderly” provides guidance on how to determine the fair value of assets and liabilities under SFAS 157 in the current economic environment and reemphasizes that the objective of a fair value measurement remains the price that would be received to sell an asset or paid to transfer a liability at the measurement date.
- **FSP SFAS 115-2 and SFAS 124-2** – FASB Staff Position No. 115-2 and 124-2, “Recognition and Presentation of Other-Than-Temporary Impairments” modifies the requirements for recognizing other-than-temporarily impaired debt securities and significantly changes the existing impairment model for such securities. It also modifies the presentation of other-than-temporary impairment losses and increases the frequency of and expands already required disclosures about other-than-temporary impairment for debt and equity securities.
- **FSP SFAS 107-1 and APB 28-1** – FASB Staff Position No. 107-1 and APB 28-1, “Interim Disclosures about Fair Value of Financial Instruments” requires disclosures of the fair value of financial instruments within the scope of SFAS 107 in interim financial statements, adding to the current requirement to make those disclosures in annual

financial statements. The staff position also requires that companies disclose the method or methods and significant assumptions used to estimate the fair value of financial instruments and a discussion of changes, if any, in the method or methods and significant assumptions during the period.

We will adopt the new staff positions as of July 1, 2009. We are currently evaluating the provisions of the staff positions and assessing the impact, if any, they may have on our financial position and results of operations.

Recent SEC Rule-Making Activity – In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserve Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.
- Reserve Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserve Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Disclosure by Geographic Area – Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and gas proved reserves.
- Non-Traditional Resources – The definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported oil and gas reserves. The SEC is coordinating with the Financial Accounting Standards Board to obtain the revisions necessary to SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies", and SFAS 69, "Disclosures About Oil and Gas Producing Activities", to provide consistency with the new rules. In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC has indicated that it will consider delaying the compliance date.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

We are an independent energy company engaged in worldwide crude oil, natural gas and NGL exploration and production. We operate primarily in the Rocky Mountains, Mid-continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel, the North Sea and West Africa.

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 2009 included:

- net loss of \$188 million, as compared with \$215 million net income for first quarter 2008;
 - \$437 million of asset impairment charges;
- collection of Ecuador power receivable, resulting in a \$46 million reversal of the allowance for doubtful accounts;
 - diluted loss per share of \$1.09, as compared with diluted earnings per share of \$1.20 for first quarter 2008;
- cash flow provided by operating activities of \$185 million, as compared with \$506 million for first quarter 2008;
 - issuance of \$1 billion in 10-year unsecured notes; and
 - repatriation of \$180 million of earnings from foreign subsidiaries.

Significant operational highlights for first quarter 2009 included:

- exploration success offshore Israel at Tamar, our largest discovery to date;
 - additional natural gas discovery offshore Israel at Dalit;
- our first oil discovery on Block O offshore Equatorial Guinea at the Carmen prospect;
- successful high bidder on 24 deepwater blocks in Central Gulf of Mexico lease sale 208; and
 - deepwater Gulf of Mexico discovery at Santa Cruz.

Impact of Recession and Current Credit and Commodity Markets – During first quarter 2009, we took initiatives to strengthen our liquidity and lengthen our weighted average debt maturities in response to ongoing uncertainty in the credit markets. In February we issued \$1 billion of 8¼% senior notes due 2019 and used substantially all of the net proceeds to repay outstanding indebtedness under our credit facility. As a result, the amount available under our credit facility increased to almost \$1.4 billion at March 31, 2009. In addition, we repatriated \$180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. See Liquidity and Capital Resources below.

As noted in our 2008 Annual Report on Form 10-K (Item 1A. Risk Factors), significant decreases in crude oil and natural gas prices could result in a reduction of the carrying values of our oil and gas properties. The commodity price decreases that began during the second half of 2008 required us to record asset impairment charges during fourth quarter 2008. Further declines in natural gas prices during first quarter 2009 led us to review those properties that, at year-end 2008, were susceptible to impairment should commodity prices continue to decline appreciably. As a result of this review, we determined that additional properties were impaired as of March 31, 2009. Total pre-tax (non-cash) impairments for first quarter 2009 were \$437 million and were predominately related to Granite Wash, an onshore US area in which we have significantly reduced investments beginning in 2007. The decrease in the natural gas futures price strip that occurred during first quarter 2009 was the primary factor that required an impairment of Granite Wash. See Item 1. Financial Statements – Note 5 – Fair Value Measurements. Further declines in commodity prices could result in additional impairment of our oil and gas properties, other long-lived assets or goodwill.

Continued lower commodity prices will reduce our cash flows from operations. To mitigate the impact of lower commodity prices on our cash flows, we have entered into crude oil commodity contracts for 2009 and 2010 and natural gas commodity contracts for 2009, 2010 and 2011. Depending on the length of the current recession, commodity prices may stay depressed or decline further, thereby causing a prolonged downturn, which would further reduce our cash flows from operations. This could cause us to alter our business plans including reducing or delaying our exploration and development program spending and other cost reduction initiatives. See 2009 Budget below.

We are closely monitoring costs and have implemented several cost savings initiatives, including continued reduction of well costs through drilling and completion efficiencies and comprehensive review of oil and gas operating costs. We are also beginning to see reductions in third party drilling costs and operating supplies and services.

OUTLOOK

Our expected crude oil, natural gas and NGL production for the remainder of 2009 may be impacted by several factors including:

- overall level and timing of capital expenditures, as discussed below, which, dependent upon our drilling success, are expected to result in near-term production growth;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-continent areas of our US operations and the North Sea;
 - higher sales of natural gas from the Alba field in Equatorial Guinea;
- potential hurricane-related volume curtailments in the Gulf of Mexico and Gulf Coast areas of our US operations as occurred with Hurricanes Gustav and Ike in 2008;
 - the restoration of pipeline and facilities necessary to increase our Gulf of Mexico production;
 - potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountains area of our US operations and timing of start-up of a new interstate crude oil transportation pipeline system which will run from Weld County, Colorado to Cushing, Oklahoma;
 - growth in demand for natural gas in Israel;
 - Israeli seasonal demand;
 - competing natural gas deliveries in Israel from Egypt, which could lower our sales volumes;
 - potential downtime at the methanol, LPG and/or LNG plants in Equatorial Guinea;
 - seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project; and
 - timing of significant project completion and initial production.

2009 Budget – Due to the uncertain economic and commodity price environment, we have designed a flexible capital spending program that will be responsive to conditions that develop during 2009. Our revised capital program for 2009 accommodates an investment level of \$1.6 billion, with the ability to adjust up or down by approximately 15%. Currently we are managing towards an investment level of \$1.4 billion, the lower end of this range.

Approximately 40% of the 2009 budget is committed to longer-term projects that will provide considerable production growth several years in the future. The remainder is allocated toward maintaining and strengthening the existing property base. Development spending will focus on our international and deepwater Gulf of Mexico assets as well as certain higher return opportunities onshore in the US including the Wattenberg field. The exploration budget will center on significant resource potential in Israel, West Africa and the deepwater Gulf of Mexico. International expenditures are estimated to represent 30% of the total capital program.

The 2009 budget does not include the impact of possible asset purchases. We expect that the remaining 2009 budget will be funded primarily from cash flows from operations, cash on hand, and borrowings under our revolving credit facility. We will evaluate the level of capital spending throughout the remainder of the year based on drilling results, commodity prices, cash flows from operations and property acquisitions and divestitures.

Recently Issued Pronouncements – See Item 1. Financial Statements – Note 15 – Recently Issued Pronouncements.

RESULTS OF OPERATIONS

Oil, Gas and NGL Sales

Revenues from sales of commodities were as follows:

	Three Months Ended March 31, 2009 2008 (in millions)	
Crude oil and condensate sales	\$ 202	\$ 527
Natural gas sales	183	371
NGL sales	21	46
Total	\$ 406	\$ 944

Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes			Average Realized Sales Prices		
	Crude Oil & Condensate (MBopd)	Natural Gas (MMcfpd)	NGLs (MBpd)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2009						
United States (1)	35	411	9	\$ 35.65	\$ 3.93	\$ 24.74
West Africa (2) (3)	13	243	-	39.41	0.27	-
North Sea	7	5	-	45.91	8.17	-
Israel	-	112	-	-	2.81	-
Ecuador (4)	-	30	-	-	-	-
Other International	4	-	-	36.89	-	-
Total Consolidated Operations	59	801	9	37.81	2.64	24.74
Equity Investees (5)	2	-	7	41.76	-	26.89
Total	61	801	16	\$ 37.91	\$ 2.64	\$ 25.62
Three Months Ended March 31, 2008						
United States (1)	43	393	9	\$ 71.33	\$ 8.97	\$ 55.15
West Africa (2) (3)	15	220	-	88.79	0.27	-
North Sea	9	6	-	100.46	9.65	-
Israel	-	145	-	-	3.04	-
Ecuador (4)	-	23	-	-	-	-
Other International	6	-	-	73.37	-	-
Total Consolidated Operations	73	787	9	78.89	5.34	55.15
Equity Investees (5)	2	-	6	98.55	-	60.78
Total	75	787	15	\$ 79.43	\$ 5.34	\$ 57.47

- (1) Average realized crude oil and condensate prices reflect reductions of \$2.70 per Bbl for first quarter 2009 and \$21.81 per Bbl for first quarter 2008 from hedging activities. Average realized natural gas prices reflect a reduction of \$0.01 for first quarter 2009 and an increase of \$1.05 per Mcf for first quarter 2008 from hedging activities. The price reductions and increase resulted from hedge gains and losses that were previously deferred in AOCL.
- (2) Average realized crude oil and condensate prices reflect reductions of \$7.08 per Bbl for first quarter 2009 and \$8.62 per Bbl for first quarter 2008 from hedging activities. The price reductions resulted from hedge losses that were previously deferred in AOCL.

⁽³⁾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. Natural gas volumes sold to the LNG plant totaled 188 MMcfpd during first quarter 2009 and 173 MMcfpd during first quarter 2008.

- (4) The natural gas-to-power project in Ecuador is 100% owned by our subsidiaries and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales are included in other revenues. See Item 1. Financial Statements – Note 2 – Basis of Presentation.
- (5) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. See Equity Method Investees below.

Crude oil and condensate sales volumes in the table above differ from actual production volumes due to the timing of liquid hydrocarbon tanker liftings. Crude oil and condensate production volumes were as follows:

	Three Months Ended March 31,	
	2009	2008
	(MBopd)	
United States	35	43
West Africa	15	15
North Sea	8	11
Other International	4	6
Total Consolidated Operations	62	75
Equity Investees	2	2
Total	64	77

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

	Three Months Ended March 31,			
	2009		2008	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
United States	\$ 56.78	\$ 5.51	\$ 70.02	\$ 8.63
West Africa	64.21	0.27	87.39	0.27
Total Consolidated Operations	55.65	3.48	77.83	5.16
Total	55.32	3.48	78.40	5.16

Crude Oil and Condensate Sales – Crude oil and condensate sales decreased during first quarter 2009 as compared with first quarter 2008 due to the significant decrease in average realized prices combined with a decline in sales volumes. The decrease in sales volumes was due to continued Hurricane Ike-related shut-ins of certain deepwater Gulf of Mexico assets, the timing of liftings in Equatorial Guinea and the North Sea and natural field decline in the North Sea.

Revenues for first quarter 2009 and 2008 included deferred losses of \$17 million and \$97 million, respectively, reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges.

Natural Gas Sales – Natural gas sales decreased during first quarter 2009 as compared with first quarter 2008 due to the significant decrease in average realized prices. The effect of the price decreases was partially offset by an overall increase in sales volumes due to the following:

- increase in production from the Wattenberg, Piceance and Tri-state areas of our North America operations; and
- increase in volumes sold to the LNG plant in Equatorial Guinea;

and partially offset by:

- decrease in Israel sales volumes due to power plant downtime and milder weather conditions; and
- continued Hurricane Ike-related shut-ins of certain deepwater Gulf of Mexico assets.

Revenues for first quarter 2008 included a deferred gain of \$37 million reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges. Revenues for first quarter 2009 included a de minimis amount reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges.

NGL Sales – Most of our US NGL production is from the Wattenberg field and deepwater Gulf of Mexico. NGL sales decreased during first quarter 2009 as compared with first quarter 2008 due to a 55% decrease in average realized NGL prices.

Equity Method Investees

Our share of operations of equity method investees, Atlantic Methanol Production Company, LLC (AMPCO) and Alba Plant LLC (Alba Plant), was as follows:

	Three Months Ended March 31,	
	2009	2008
Net income (in millions):		
AMPCO and affiliates	\$ -	\$ 28
Alba Plant	11	34
Distributions/dividends (in millions):		
AMPCO and affiliates	\$ -	\$ 34
Alba Plant	-	42
Production volumes:		
Methanol (MMgal)	40	34
Condensate (MBopd)	2	2
LPG (MBpd)	6	6
Sales volumes:		
Methanol (MMgal)	35	34
Condensate (MBopd)	2	2
LPG (MBpd)	7	6
Average realized prices:		
Methanol (per gallon)	\$ 0.46	\$ 1.63
Condensate (per Bbl)	41.76	98.55
LPG (per Bbl)	26.89	60.78

The decrease in net income for each of the equity method investees for first quarter 2009 as compared with first quarter 2008 was due to significant decreases in average realized prices. No distributions were made during first quarter 2009 due to the decreases in net income and in anticipation of planned tax payments.

Other Revenues

Other revenues include electricity sales and GMP revenues. See Item 1. Financial Statements – Note 2 – Basis of Presentation.

Costs and Expenses

Production Costs – Production costs were as follows:

	Total	United States	West Africa (in millions)	North Sea	Israel	Other Int'l, Corporate(1)
Three Months Ended March 31, 2009						
Oil and gas operating costs (2)	\$ 93	\$ 71	\$ 9	\$ 9	\$ 1	\$ 3
Workover and repair expense	7	6	-	1	-	-
Lease operating expense	100	77	9	10	1	3
Production and ad valorem taxes	18	18	-	-	-	-
Transportation expense	12	10	-	1	-	1
Total production costs	130	105	9	11	1	4
Three Months Ended March 31, 2008						
Oil and gas operating costs (2)	76	49	9	11	2	5
Workover and repair expense	6	6	-	-	-	-
Lease operating expense	82	55	9	11	2	5
Production and ad valorem taxes	43	33	-	-	-	10
Transportation expense	13	11	-	2	-	-
Total production costs	\$ 138	\$ 99	\$ 9	\$ 13	\$ 2	\$ 15

(1) Other international includes Ecuador, China, and Argentina (through February 2008).

(2) Oil and gas operating costs include labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs.

Total production costs decreased first quarter 2009 as compared with first quarter 2008 primarily due to a decrease in production and ad valorem taxes offset by an increase in oil and gas operating costs. Production and ad valorem taxes in the US decreased primarily due to lower commodity prices. Other International production taxes were de minimis for first quarter 2009 due to lower commodity prices in China and the sale of our oil and gas interests in Argentina. US oil and gas operating costs increased primarily due to an increase in well counts, production volumes and water disposal costs in the Northern region, and were partially offset by a decrease in International operating costs.

Selected expenses on a per BOE basis were as follows:

	Three Months Ended March 31,	
	2009	2008
Oil and gas operating costs	\$ 5.09	\$ 3.88
Workover and repair expense	0.41	0.33
Lease operating expense	5.50	4.21

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Production and ad valorem taxes	1.00	2.23
Transportation expense	0.63	0.68
Total production costs (1) (2)	\$ 7.13	\$ 7.12

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea. The inclusion of these volumes reduced the unit rate by \$1.30 per BOE for first quarter 2009 and \$1.11 per BOE for first quarter 2008.

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

Oil and Gas Exploration Expense – Oil and gas exploration expense was as follows:

	Total	United States	West Africa (in millions)	North Sea	Israel	Other Int'l/ Corporate (1)
Three Months Ended March 31, 2009						
Dry hole expense	\$ 2	\$ (1)	\$ 4	\$ -	\$ -	\$ (1)
Seismic	23	23	-	-	-	-
Staff expense	15	4	3	1	-	7
Other	2	2	-	-	-	-
Total exploration expense	\$ 42	\$ 28	\$ 7	\$ 1	\$ -	\$ 6
Three Months Ended March 31, 2008						
Dry hole expense	\$ 7	\$ (1)	\$ -	\$ 8	\$ -	\$ -
Seismic	13	13	-	-	-	-
Staff expense	16	11	-	1	1	3
Other	4	4	-	-	-	-
Total exploration expense	\$ 40	\$ 27	\$ -	\$ 9	\$ 1	\$ 3

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

Oil and gas exploration expense for first quarter 2009 includes an increase in US seismic expense in support of the central Gulf of Mexico lease sale. Exploration expense also includes stock-based compensation expense of \$2 million for first quarter 2009 and less than \$1 million for first quarter 2008.

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

	Three Months Ended March 31, 2009 2008 (in millions, except unit rate)	
DD&A expense	\$ 197	\$ 201
Accretion of discount on asset retirement obligations	3	2
Total DD&A expense	\$ 200	\$ 203
Unit rate per BOE (1)	\$ 11.01	\$ 10.42

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea. The inclusion of these volumes reduced the unit rate by \$1.67 per BOE for first quarter 2009 and \$1.32 per BOE for first quarter 2008.

Total DD&A expense for first quarter 2009 remained flat as compared with first quarter 2008. DD&A expense was higher in the US due to an increase in Northern region production (primarily in Piceance and Wattenberg), offset somewhat by decreased production in the Gulf of Mexico. DD&A expense also included \$4 million of abandoned

asset expense in first quarter 2009.

The higher DD&A unit rate resulted from the change in our mix of production, including lower volumes in Israel, and was also impacted by negative reserve revisions related to lower year-end 2008 commodity prices.

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

	Three Months Ended March 31,	
	2009	2008
G&A expense (in millions)	\$ 59	\$ 60
Unit rate per BOE (1)	\$ 3.23	\$ 3.09

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea. The inclusion of these volumes reduced the unit rate by \$0.59 per BOE for first quarter 2009 and \$0.48 per BOE for first quarter 2008.

G&A expense during first quarter 2009 remained flat as compared with first quarter 2008. G&A expense included stock-based compensation expense of \$9 million in each of first quarter 2009 and 2008, respectively.

Asset Impairments – During first quarter 2009 we recorded total pre-tax (non-cash) impairment charges of \$437 million on certain US oil and gas properties, primarily due to lower natural gas prices. In determining the fair values of the impaired properties, we applied the fair value definition of SFAS 157. SFAS 157 requires that fair values be determined from the perspective of a market participant considering, among other things, appropriate discount rates, multiple valuation techniques, the most advantageous market and assumptions around the highest and best use of the assets. Due to the absence of comparable market data for the impaired properties, we estimated the fair values using a discounted cash flow method. Estimated future cash flows were based on management's expectations for the future and included management's estimates of future oil and gas production, commodity prices based on commodity futures price strips as of March 31, 2009, operating and development costs, as well as appropriate discount rates. Due to the use of significant unobservable inputs, the fair values of the impaired properties were classified as Level 3 measurements in the fair value hierarchy. A change in any of the assumptions used, such as a significant increase or decreased in estimated commodity prices or production, could have had a significant impact on the amount of the impairment loss recognized. See Item 1. Financial Statements – Note 5 – Fair Value Measurements.

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

(Gain) Loss on Commodity Derivative Instruments – See Item 1. Financial Statements – Note 4 – Derivative Instruments and Hedging Activities and Note 5 – Fair Value Measurements.

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

	Three Months Ended March 31,	
	2009	2008
	(in millions)	
Interest expense	\$ 24	\$ 27
Capitalized interest	(6)	(10)
Interest expense, net	\$ 18	\$ 17

Interest expense decreased during first quarter 2009, as compared with first quarter 2008 due to a declining rate of interest applicable to our credit facility from 2.99% at March 31, 2008 to 0.81% at March 31, 2009, offset by a higher rate of interest related to the issuance of \$1 billion 10-year unsecured notes on February 27, 2009. The amount of interest capitalized decreased primarily due to a lower average interest rate applicable to our long-term debt.

Other (Income) Expense, Net – See Item 1. Financial Statements – Note 2 – Basis of Presentation.

Income Tax Provision (Benefit) – The income tax provision (benefit) was as follows:

	Three Months Ended March 31,	
	2009	2008
Income tax provision (benefit) (in millions)	\$ (186)	\$ 101
Effective rate	50%	32%

Our effective tax rate increased during first quarter 2009 as compared with first quarter 2008 due primarily to the fact that the 2009 rate represents a tax benefit divided by a pre-tax loss. In that case, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary cash needs are to fund operating expenses and capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings and associated interest payments and other contractual commitments and to pay dividends. Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under credit facilities. Occasional sales of non-strategic crude oil and natural gas properties may also generate cash.

The ongoing disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our investments as well as the securities underlying our investments. Thus far, our liquidity and financial position have not been materially impacted. However, further deterioration in the credit markets could adversely affect our results of operations and cash flows. See Executive Overview – Impact of Recession and Current Credit and Commodity Markets.

Cash and Cash Equivalents – We had \$1.0 billion in cash and cash equivalents at March 31, 2009. Our cash is denominated in US dollars and is invested in US Treasury securities and short-term deposits with major financial institutions. In response to the credit market crisis, we shortened the duration of our investment maturities and increased our investments in US Treasury securities.

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 a majority of our international cash to fund international projects, including the development of West Africa and Israel.

During fourth quarter 2008, we performed an analysis of projected short-term working capital needs as well as long-term capital requirements for our US and foreign operations. As a result, we repatriated \$180 million of the accumulated earnings of foreign subsidiaries during first quarter 2009. We used the proceeds for debt repayment and general corporate purposes. See Item 1. Financial Statements – Note 4 – Income Taxes for a discussion of the related tax effects.

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

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of March 31, 2009, the fair value of our commodity derivative assets was \$427 million and the fair value of our commodity derivative liabilities was \$46 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 for a description of the methods we use to estimate the fair values of commodity derivative instruments.

Contractual Obligations

In February 2009, we completed an underwritten public offering of \$1 billion of 8¼% senior unsecured notes due March 1, 2019. See Financing Activities below. As a result, our future debt principal payments as of March 31, 2009 consist of the following: \$25 million for the remainder of 2009; \$726 million for 2012; and \$1.6 billion for 2014 and beyond for a total of \$2.4 billion. Based on the total debt balance, scheduled maturities and interest rates in effect at March 31, 2009, our cash payments for interest would be \$88 million for the remainder of 2009; \$133 million in 2010; \$133 million in 2011; \$132 million in 2012; \$127 million in 2013; and \$1.3 billion for the remaining years for a total of \$2.0 billion. See Item 1. Financial Statements – Note 3 – Debt Issuance.

Cash Flows

Cash flow information is as follows:

	Three Months Ended March 31,	
	2009	2008
	(in millions)	
Total cash provided by (used in):		
Operating activities	\$ 185	\$ 506
Investing activities	(399)	(355)
Financing activities	91	(4)
Increase (decrease) in cash and cash equivalents	\$ (123)	\$ 147

Operating Activities – Net cash provided by operating activities for first quarter 2009 decreased as compared with first quarter 2008 due primarily to decreases in commodity prices.

Investing Activities – Our investing activities include capital spending for oil and gas properties, which may be offset by proceeds from property sales. Net cash used in investing activities increased during first quarter 2009 as compared with first quarter 2008 and consisted only of capital spending. First quarter 2008 activity included capital spending of \$464 million, which was partially offset by net proceeds of \$109 million from asset sales. See Acquisition, Capital and Exploration Expenditures below.

Financing Activities – Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During first quarter 2009, we received \$989 million net proceeds from the issuance of our 8¼% senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options (\$14 million). We used cash for net repayments of amounts outstanding under our revolving credit facility (\$880 million), to pay dividends on our common stock (\$31 million), and to repurchase shares of our common stock (\$1 million).

In comparison, during first quarter 2008, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options (\$19 million) and we used cash to pay dividends on our common stock (\$21 million) and repurchase shares of our common stock (\$2 million). There were no net changes in outstanding debt.

Investing Activities

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

	Three Months Ended March 31,	
	2009	2008
	(in millions)	
Acquisition, Capital and Exploration Expenditures		
Unproved property acquisition	\$ 16	\$ 176
Exploration	95	45
Development	231	246
Corporate and other	44	19
Total	\$ 386	\$ 486

Unproved property acquisition costs for first quarter 2009 and 2008 include primarily lease bonuses on deepwater lease blocks acquired in central Gulf of Mexico lease sales.

Property Sales – In February 2008, effective July 1, 2007, we sold our interest in Argentina for a sales price of \$117.5 million.

Financing Activities

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

In order to provide increased liquidity and lengthen our weighted average debt maturity, on February 27, 2009 we completed an underwritten public offering of \$1 billion of 8¼% senior unsecured notes due March 1, 2019, receiving net proceeds of \$989 million. We used substantially all of the net proceeds from the offering to repay outstanding indebtedness under the revolving credit facility.

As a result, at March 31, 2009, borrowings outstanding under the credit facility totaled \$726 million, leaving almost \$1.4 billion available for use. The weighted average interest rate applicable to borrowings under the credit facility at March 31, 2009 was 0.81%.

Our outstanding fixed-rate debt, including the new 8¼% senior unsecured notes discussed above, totaled \$1.6 billion at March 31, 2009. The weighted average interest rate on fixed-rate debt was 7.73%, with maturities ranging from 2014 to 2097.

Our ratio of debt-to-book capital was 28% at March 31, 2009 as compared with 26% at December 31, 2008. We define our ratio of debt-to-book capital as total debt (which includes both long-term debt, excluding unamortized discount, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Short-Term Borrowings – We owe \$25 million in the form of an installment payment to the seller of properties we purchased in 2007. The amount is due May 11, 2009 and is included in short-term borrowings in the consolidated balance sheets. Interest on the unpaid amount is due quarterly and accrues at a LIBOR rate plus .30%. The interest rate was 1.76% at March 31, 2009.

Our committed credit facility has been 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, 2009 or December 31, 2008. 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 a quarterly cash dividend of 18.0 cents per share of common stock during first quarter 2009 and 12.0 cents per share of common stock during first quarter 2008. On April 27, 2009, our Board of Directors declared a quarterly cash dividend of 18.0 cents per common share, payable May 26, 2009 to shareholders of record on May 11, 2009. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options – We received cash proceeds of \$11 million from the exercise of stock options during first quarter 2009 as compared with \$10 million during first quarter 2008.

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 17,510 shares with a value of \$1 million during first quarter 2009 and 24,380 shares with a value of \$2 million during first quarter 2008.

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, 2009, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Our open commodity derivative instruments were in a net receivable position with a fair value of \$381 million. Based on the March 31, 2009 published forward commodity price curves for the underlying commodities, a price increase of \$1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately \$9 million. A price increase of \$0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately \$8 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 other variable-rate debt and the amount of interest we earn on our short-term investments.

At March 31, 2009, we had \$2.4 billion (excluding unamortized discount) of long-term debt outstanding. Of this amount, \$1.6 billion was fixed-rate debt with a weighted average interest rate of 7.73%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss.

The remainder of our long-term debt, \$726 million at March 31, 2009, was variable-rate debt drawn under our credit facility. We also had \$25 million of short-term variable-rate debt at March 31, 2009. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the March 31, 2009 balance of our variable-rate debt would result in a change in annual interest expense of approximately \$2 million.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate “locks” used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At March 31, 2009, AOCL included \$2 million, net of tax, related to interest rate locks. This amount is currently being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014.

We are also exposed to interest rate risk related to our short-term investments. As of March 31, 2009, approximately 46% of our cash was invested in US Treasury securities. A hypothetical 25 basis point change in the floating interest rates applicable to the March 31, 2009 balance would result in a change in annual interest income of approximately \$1 million.

Foreign Currency Risk

We have not entered into foreign currency derivative instruments. The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in a foreign currency are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. We do not have any significant monetary assets or liabilities denominated in a foreign currency other than our foreign deferred tax liabilities in certain foreign tax jurisdictions. An increase in exchange rates between the US dollar and the currency of the foreign tax jurisdiction in which these liabilities are located could result in the use of additional cash to settle these liabilities. However, transaction gains or losses were not material in any of the periods presented and we do not believe we are currently exposed to any material risk of loss on this basis. Such gains or losses are included in other (income) expense, net in the consolidated statements of operations.

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:

- the extent and effect of any hedging activities engaged in by us;
- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- effect of current volatility in the credit markets;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “anticipate,” “estimate” 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 2008 annual report on Form 10-K, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our 2008 annual report on Form 10-K 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 Charles D. Davidson, our principal executive officer, and Chris Tong, 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, 2008, other than the following:

The proposed United States federal budget for fiscal year 2010 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 26, 2009, the Office of Management and Budget released a summary of the President's proposed federal budget for fiscal year 2010. The proposed budget repeals many tax incentives and deductions that are currently used by US oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands.

Should some or all of these provisions become law our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

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)
01/01/09 - 01/31/09	786	\$ 51.02	-	-
02/01/09 - 02/28/09	16,724	50.21	-	-
03/01/09 - 03/31/09	-	-	-	-
Total	17,510	\$ 50.24	-	-

(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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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 as amended, 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 30, 2009

/s/ CHRIS TONG
CHRIS TONG
Senior Vice President and Chief Financial Officer

INDEX TO EXHIBITS

Exhibit
Number

Exhibit

- 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).
- 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).
- 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).
- 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).

