NOBLE ENERGY INC
Form 10-Q
April 24, 2014

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

FORM 10-Q

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

For the quarterly period ended March 31, 2014

OR

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

For the transition period from _____to_____

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

Delaware	73-0785597
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
1001 Noble Energy Way	
Houston, Texas	77070
(Address of principal executive offices)	(Zip Code)

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

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

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

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

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

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

As of March 31, 2014, there were 360,740,081 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements
Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)
(unaudited)

	Three Months Ended March 31,	
	2014	2013
Revenues		
Oil, Gas and NGL Sales	$1,327	$1,083
Income from Equity Method Investees	52	60
Total	1,379	1,143
Costs and Expenses		
Production Expense	232	187
Exploration Expense	74	61
Depreciation, Depletion and Amortization	425	366
General and Administrative	140	112
Asset Impairments	97	—
Other Operating (Income) Expense, Net	7	(8)
Total	975	718
Operating Income	404	425
Other (Income) Expense		
Loss on Commodity Derivative Instruments	75	72
Interest, Net of Amount Capitalized	47	25
Other Non-Operating Expense, Net	5	10
Total	127	107
Income from Continuing Operations Before Income Taxes	277	318
Income Tax Provision	77	86
Income from Continuing Operations	200	232
Discontinued Operations, Net of Tax	—	29
Net Income	$200	$261
Earnings Per Share, Basic		
Income from Continuing Operations	$0.56	$0.65
Discontinued Operations, Net of Tax	—	0.08
Net Income	$0.56	$0.73
Earnings Per Share, Diluted		
Income from Continuing Operations	$0.55	$0.64
Discontinued Operations, Net of Tax	—	0.08
Net Income	$0.55	$0.72
Weighted Average Number of Shares Outstanding		
Basic	360	358
Diluted	365	362

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

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Noble Energy, Inc.
Consolidated Statements of Comprehensive Income
(millions)
(unaudited)

	Three Months Ended March 31,	
	2014	2013
Net Income	$200	$261
Other Items of Comprehensive Income		
Net Change in Pension and Other	5	6
Less Tax Benefit	(2)	(2)
Other Comprehensive Income	3	4
Comprehensive Income	$203	$265

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

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

	March 31, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,354	$1,117
Accounts Receivable, Net	865	947
Other Current Assets	545	547
Total Current Assets	2,764	2,611
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	22,837	22,243
Property, Plant and Equipment, Other	564	517
Total Property, Plant and Equipment, Gross	23,401	22,760
Accumulated Depreciation, Depletion and Amortization	(7,284)	(7,035)
Total Property, Plant and Equipment, Net	16,117	15,725
Goodwill	621	627
Other Noncurrent Assets	690	679
Total Assets	$20,192	$19,642
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,178	$1,354
Other Current Liabilities	1,021	988
Total Current Liabilities	2,199	2,342
Long-Term Debt	5,011	4,566
Deferred Income Taxes, Noncurrent	2,449	2,441
Other Noncurrent Liabilities	1,172	1,109
Total Liabilities	10,831	10,458
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	—	—
Common Stock - Par Value $0.01 per share; 500 Million Shares Authorized; 401 Million and 400 Million Shares Issued, respectively	4	4
Additional Paid in Capital	3,502	3,463
Accumulated Other Comprehensive Loss	(114)	(117)
Treasury Stock, at Cost; 38 Million Shares	(674)	(659)
Retained Earnings	6,643	6,493
Total Shareholders' Equity	9,361	9,184
Total Liabilities and Shareholders' Equity	$20,192	$19,642

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

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

	Three Months Ended March 31,	
	2014	2013
Cash Flows From Operating Activities		
Net Income	$200	$261
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	425	367
Asset Impairments	97	—
Deferred Income Taxes	17	52
Income from Equity Method Investees, Net of Dividends	(13)	(35)
Loss on Commodity Derivative Instruments	75	72
Net Cash Received (Paid) in Settlement of Commodity Derivative Instruments	(33)	7
(Gain) Loss on Divestitures	1	(53)
Stock Based Compensation	23	18
Other Adjustments for Noncash Items Included in Income	20	25
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	28	(56)
Increase in Accounts Payable	57	82
Increase in Current Income Taxes Payable	47	—
Decrease in Other Current Liabilities	(25)	(48)
Other Operating Assets and Liabilities, Net	10	13
Net Cash Provided by Operating Activities	929	705
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,158)	(806)
Additions to Equity Method Investments	(12)	(20)
Proceeds from Divestitures	92	76
Other	—	2
Net Cash Used in Investing Activities	(1,078)	(748)
Cash Flows From Financing Activities		
Exercise of Stock Options	10	22
Excess Tax Benefits from Stock-Based Awards	6	9
Dividends Paid, Common Stock	(50)	(44)
Purchase of Treasury Stock	(15)	(14)
Proceeds from Credit Facilities	450	—
Repayment of Capital Lease Obligation	(15)	(12)
Net Cash Provided by (Used in) Financing Activities	386	(39)
Increase (Decrease) in Cash and Cash Equivalents	237	(82)
Cash and Cash Equivalents at Beginning of Period	1,117	1,387
Cash and Cash Equivalents at End of Period	$1,354	$1,305

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

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

	Common Stock [1]	Additional Paid in Capital [1]	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2013	$4	$3,463	$(117)	$(659)	$6,493	$9,184
Net Income	—	—	—	—	200	200
Stock-based Compensation	—	23	—	—	—	23
Exercise of Stock Options	—	10	—	—	—	10
Tax Benefits Related to Exercise of Stock Options	—	6	—	—	—	6
Dividends (14 cents per share)	—	—	—	—	(50)	(50)
Changes in Treasury Stock, Net	—	—	—	(15)	—	(15)
Net Change in Pension and Other	—	—	3	—	—	3
March 31, 2014	$4	$3,502	$(114)	$(674)	$6,643	$9,361
December 31, 2012	$4	$3,302	$(113)	$(648)	$5,713	$8,258
Net Income	—	—	—	—	261	261
Stock-based Compensation	—	18	—	—	—	18
Exercise of Stock Options	—	22	—	—	—	22
Tax Benefits Related to Exercise of Stock Options	—	9	—	—	—	9
Dividends (12.5 cents per share)	—	—	—	—	(44)	(44)
Changes in Treasury Stock, Net	—	—	—	(14)	—	(14)
Net Change in Pension and Other	—	—	4	—	—	4
March 31, 2013	$4	$3,351	$(109)	$(662)	$5,930	$8,514

[1] Amounts reflect impact of 2-for-1 stock split which occurred during the second quarter of 2013.

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

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Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations
Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our core operating areas are onshore US, primarily in the DJ Basin and Marcellus Shale, in the deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Note 2. Basis of Presentation
Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US GAAP for complete financial statements. The accompanying consolidated financial statements at March 31, 2014 and December 31, 2013 and for the three months ended March 31, 2014 and 2013 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three months ended March 31, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014.
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, 2013.
Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.
Discontinued Operations In 2012, we initiated a strategy to exit the North Sea geographical area through sales of our non-operated working interests in the assets. The North Sea geographical segment was classified as held for sale and the operations were reflected as discontinued operations in 2012 and 2013.
The most significant North Sea assets were sold during 2012 and 2013. However, we have been unable to locate purchasers for the remaining assets, and a sale is no longer considered probable. Therefore, during first quarter 2014, we reclassified the remaining North Sea assets to held and used, and the North Sea geographical segment is included in continuing operations in first quarter 2014. In addition, we recorded an impairment in first quarter 2014.
North Sea revenues and operating expenses for first quarter 2014, except for the impairment, were de minimis. See Note 3. Divestitures, Note 4. Asset Impairments, and Note 7. Fair Value Measurements and Disclosures.
Common Stock Split On April 22, 2013, Noble Energy's Board of Directors approved a 2-for-1 split of its common stock to be effected in the form of a stock dividend. The stock dividend was distributed on May 28, 2013 to shareholders of record as of May 14, 2013. Earnings per share and common shares outstanding are reported giving retrospective effect to the common stock split.
Recently Issued Accounting Standards In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. We are currently evaluating the provisions of ASU 2014-08 and assessing the impact, if any, it may have on our financial position and results of operations.
Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors,

including the current economic and commodity price environment.

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

(millions)	Three Months Ended March 31, 2014	2013
Production Expense		
Lease Operating Expense	$145	$117
Production and Ad Valorem Taxes	49	43
Transportation and Gathering Expense	38	27
Total	$232	$187
Other Operating (Income) Expense, Net		
(Gain) Loss on Divestitures	$1	$(15)
Other, Net	6	7
Total	$7	$(8)
Other Non-Operating (Income) Expense, Net		
Deferred Compensation Expense [1]	$4	$10
Other Expense, Net	1	—
Total	$5	$10

[1] Amounts represent increases in the fair value of shares of our common stock held in a rabbi trust.

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Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	March 31, 2014	December 31, 2013
Accounts Receivable, Net		
Commodity Sales	$403	$495
Joint Interest Billings	364	382
Other	111	81
Allowance for Doubtful Accounts	(13)	(11)
Total	$865	$947
Other Current Assets		
Inventories, Materials and Supplies	$113	$96
Inventories, Crude Oil	24	25
Deferred Income Taxes, Net	38	62
Assets Held for Sale (1)	294	292
Prepaid Expenses and Other Current Assets	76	72
Total	$545	$547
Other Noncurrent Assets		
Equity Method Investments	$464	$437
Mutual Fund Investments	116	114
Commodity Derivative Assets	11	16
Other Assets	99	112
Total	$690	$679
Other Current Liabilities		
Production and Ad Valorem Taxes	$101	$103
Commodity Derivative Liabilities	95	65
Income Taxes Payable	210	156
Asset Retirement Obligations	39	39
Interest Payable	61	63
Current Portion of Long Term Debt (2)	200	200
Current Portion of Capital Lease Obligations and Other (2)	55	58
Liabilities Associated with Assets Held for Sale (1)	58	111
Other	202	193
Total	$1,021	$988
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$263	$253
Asset Retirement Obligations	616	547
Accrued Benefit Costs	107	155
Other	186	154
Total	$1,172	$1,109

(1) Assets held for sale as of March 31, 2014 include oil and gas properties located onshore US, offshore Israel, and offshore China. Assets held for sale as of December 31, 2013 include oil and gas properties located onshore US, offshore China, and the North Sea. Liabilities associated with assets held for sale primarily include asset retirement obligations. See Note 3. Divestitures.

(2) See Note 6. Debt.

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Note 3. Divestitures
Onshore US Properties During the first three months of 2014, we sold certain non-core onshore US crude oil and natural gas properties. The information regarding the assets sold is as follows:

(millions)	Three Months Ended March 31, 2014
Sales Proceeds	$92
Less	
Net Book Value of Assets Sold	(106)
Goodwill Allocated to Assets Sold	(6)
Asset Retirement Obligations Associated with Assets Sold	20
Other Closing Adjustments	(1)
Loss on Divestitures	$(1)

Offshore Israel Properties Assets held for sale as of March 31, 2014, include two natural gas discoveries, offshore Israel. We expect to divest these assets pursuant to an agreement we and our partners reached with the Israeli Antitrust Authority in March 2014 on various antitrust matters. The agreement is subject to final approval of the Israeli government. The assets are held for sale at their carrying amounts as expected sales proceeds, less costs to sell, exceed the carrying amounts.
North Sea Properties During the first three months of 2013, we sold non-operated working interests in properties located in the North Sea. The sales resulted in a $37 million gain based on net sales proceeds of $38 million. See Note 2. Basis of Presentation - Discontinued Operations.
Summarized results of discontinued operations are as follows:

(millions)	Three Months Ended March 31, 2013
Oil and Gas Sales	$10
Income Before Income Taxes	(1)
Income Tax Expense	7
Operating Income (Loss), Net of Tax	(8)
Gain on Sale, Net of Tax	37
Discontinued Operations, Net of Tax	$29

Note 4. Asset Impairments
Pre-tax (non-cash) asset impairment charges were as follows:

(millions)	Three Months Ended March 31, 2014	2013
North Sea Property	$92	$—
Non-Core US Property	5	—
Total	$97	$—

During first quarter 2014, we recorded pre-tax asset impairment expense of $97 million. Approximately $92 million was related to the North Sea. In March 2014, the operator of one of the remaining fields notified the working interest owners that expected field abandonment costs would be higher than originally projected. The operator also notified the working interest owners that it would begin working with the appropriate regulatory agency for approval of cessation of production and subsequent field abandonment sooner than anticipated.

As a result of this new information, we adjusted the asset retirement obligation to reflect the updated estimate of abandonment costs and timing. We assessed the asset for impairment and determined that it was impaired. The impairment charge was included in consolidated income from continuing operations. See Note 2. Basis of Presentation and Note 7. Fair Value Measurements and Disclosures.

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Note 5. Derivative Instruments and Hedging Activities
Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil and natural gas prices on the majority of our production. In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows relating to the marketing of our global crude oil and domestic natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. We also may enter into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing.
While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates. See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.
Unsettled Commodity Derivative Instruments As of March 31, 2014, we had entered into the following crude oil derivative instruments:

Settlement Period	Type of Contract	Index [1]	Bbls Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2014							
2014	Swaps	NYMEX WTI	37,000	$92.67	$—	$—	$—
2014	Swaps	Dated Brent	13,000	103.21	—	—	—
2014	Three-Way Collars	NYMEX WTI	12,000	—	75.67	90.67	100.88
2014	Three-Way Collars	Dated Brent	8,000	—	84.38	98.25	121.56
2015	Swaps	NYMEX WTI	21,000	88.05	—	—	—
2015	Swaps	Dated Brent	9,000	100.16	—	—	—
2015	Three-Way Collars	NYMEX WTI	18,000	—	70.56	87.50	94.34
2015	Three-Way Collars	Dated Brent	13,000	—	76.92	96.00	108.49
2016	Swaps	Dated Brent	4,000	95.84	—	—	—
2016	Three-Way Collars	Dated Brent	6,000	—	80.00	95.00	105.87

[1] West Texas Intermediate

As of March 31, 2014, we had entered into the following natural gas derivative instruments:

Settlement Period	Type of Contract	Index [1]	MMBtu Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2014							
2014	Swaps	NYMEX HH	60,000	$4.24	$—	$—	$—
2014	Three-Way Collars	NYMEX HH	230,000	—	2.83	3.75	4.98
2015	Swaps	NYMEX HH	110,000	4.30	—	—	—
2015	Three-Way Collars	NYMEX HH	120,000	—	3.54	4.25	5.06

[1] Henry Hub

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2014		December 31, 2013		March 31, 2014		December 31, 2013	
(millions)	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	$—	Current Assets	$1	Current Liabilities	$95	Current Liabilities	$65
	Noncurrent Assets	11	Noncurrent Assets	16	Noncurrent Liabilities	16	Noncurrent Liabilities	10
Total		$11		$17		$111		$75

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

	Three Months Ended March 31,	
(millions)	2014	2013
Loss on Commodity Derivative Instruments		
Crude Oil	$55	$49
Natural Gas	20	23
Total Loss on Commodity Derivative Instruments	75	72
Cash (Received) Paid in Settlement of Commodity Derivative Instruments		
Crude Oil	27	8
Natural Gas	6	(15)
Total Cash (Received) Paid in Settlement of Commodity Derivative Instruments	33	(7)
Non-cash Portion of Loss on Commodity Derivative Instruments		
Crude Oil	28	41
Natural Gas	14	38
Total Non-cash Portion of Loss on Commodity Derivative Instruments	$42	$79

AOCL Accumulated other comprehensive loss (AOCL) at March 31, 2014 included deferred losses of $24 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due April 2014 and March 2041. The amount of deferred losses (net of tax) which will be reclassified to earnings during the next 12 months, and recorded as an increase in interest expense, is de minimis.

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Notes to Consolidated Financial Statements

Note 6. Debt
Debt consists of the following:

(millions, except percentages)	March 31, 2014 Debt		Interest Rate		December 31, 2013 Debt		Interest Rate	
Credit Facility, due October 3, 2018	$450		1.43	%	$—		—	%
Capital Lease and Other Obligations	351		—		359		—	
5¼% Senior Notes, due April 15, 2014 [1]	200		5.25	%	200		5.25	%
8¼% Senior Notes, due March 1, 2019	1,000		8.25	%	1,000		8.25	%
4.15% Senior Notes, due December 15, 2021	1,000		4.15	%	1,000		4.15	%
7¼% Senior Notes, due October 15, 2023	100		7.25	%	100		7.25	%
8% Senior Notes, due April 1, 2027	250		8.00	%	250		8.00	%
6% Senior Notes, due March 1, 2041	850		6.00	%	850		6.00	%
5¼% Senior Notes, due November 15, 2043	1,000		5.25	%	1,000		5.25	%
7¼% Senior Debentures, due August 1, 2097	84		7.25	%	84		7.25	%
Total	5,285				4,843			
Unamortized Discount	(19	)			(19	)		
Total Debt, Net of Discount	5,266				4,824			
Less Amounts Due Within One Year								
5¼% Senior Notes, due April 15, 2014, net of discount [1]	(200	)			(200	)		
Capital Lease Obligations	(55	)			(58	)		
Long-Term Debt Due After One Year	$5,011				$4,566			

[1] We repaid the Senior Notes on their due date.

Credit Facility Our Credit Agreement provides for a $4.0 billion unsecured revolving credit facility (Credit Facility), which is available for general corporate purposes. The Credit Facility (i) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (ii) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 100 basis points to 145 basis points depending upon our credit rating.

See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Note 7. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

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

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

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

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [2]	Significant Unobservable Inputs (Level 3) [3]	Adjustment [4]	Fair Value Measurement
March 31, 2014					
Financial Assets					
Mutual Fund Investments	$116	$—	$—	$—	$116
Commodity Derivative Instruments	—	15	—	(4)	11
Financial Liabilities					
Commodity Derivative Instruments	—	(115)	—	4	(111)
Portion of Deferred Compensation Liability Measured at Fair Value	(181)	—	—	—	(181)
December 31, 2013					
Financial Assets					
Mutual Fund Investments	$114	$—	$—	$—	$114
Commodity Derivative Instruments	—	28	—	(11)	17
Financial Liabilities					
Commodity Derivative Instruments	—	(86)	—	11	(75)
Portion of Deferred Compensation Liability Measured at Fair Value	(176)	—	—	—	(176)

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments Information about impaired assets is as follows:

	Fair Value Measurements Using				
Description	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value [1]	Total Pre-tax (Non-cash) Impairment Loss
millions					
Three Months Ended March 31, 2014					
Impaired Oil and Gas Properties	$—	$—	$6	$103	$97
Three Months Ended March 31, 2013					
Impaired Oil and Gas Properties	—	—	—	—	—

(1) Amount represents net book value at the date of assessment.

The fair value of impaired oil and gas properties was determined as of the date of the assessment using a discounted cash flow model based on management's expectations of future crude oil production prior to abandonment date, commodity prices based on the Brent future price curve as of the date of the estimate, estimated operating and abandonment costs, and a risk-adjusted discount rate of 10%. First quarter 2014 impairment costs were due to increased cost and change in timing of abandonment activities. See Note 4. Asset Impairments.

Additional Fair Value Disclosures

Debt The fair value of public, fixed-rate debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public, fixed-rate debt to be a Level 1 measurement on the fair value hierarchy.

The carrying amount of our Credit Facility at March 31, 2014 approximates fair value because the interest rate paid on such debt is set for periods of three months or less. As such, we consider the fair values of our Credit Facility to be a Level 2 measurements on the fair value hierarchy. See Note 6. Debt.

Fair value information regarding our debt is as follows:

(millions)	March 31, 2014 Carrying Amount	Fair Value	December 31, 2013 Carrying Amount	Fair Value
Total Debt, Net of Unamortized Discount [1]	$4,915	$5,524	$4,465	$4,959

[1] Excludes capital lease and other obligations.

Note 8. Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. If a well is deemed to be noncommercial, the well costs are charged to exploration expense as dry hole cost.

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

(millions)	Three Months Ended March 31, 2014
Capitalized Exploratory Well Costs, Beginning of Period	$1,301
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	72
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale	(76)
Capitalized Exploratory Well Costs Charged to Expense	(2)
Capitalized Exploratory Well Costs, End of Period	$1,295

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced, and the number of projects that have been capitalized for a period greater than one year:

(millions)	March 31, 2014	December 31, 2013
Exploratory Well Costs Capitalized for a Period of One Year or Less	$465	$568
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	830	733
Balance at End of Period	$1,295	$1,301
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	12	13

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 commencement of drilling as of March 31, 2014:

(millions)	Total	Suspended Since 2012 - 2013	2010 - 2011	2009 & Prior	Progress
Country/Project:					
Offshore Equatorial Guinea					
Diega (including Carmen)	$106	$1	$52	$53	Evaluating regional development scenarios for this 2008 crude oil discovery
Carla	123	111	12	—	Evaluating regional development scenarios for this 2011 crude oil discovery
Felicita	37	2	6	29	Evaluating regional development plans for this 2008 condensate and natural gas discovery
Yolanda	18	1	3	14	Evaluating regional development plans for this 2007 condensate and natural gas discovery
Offshore Cameroon					
YoYo	46	3	9	34	Working with the government to assess commercialization of this 2007 condensate and natural gas discovery
Offshore Israel					
Leviathan	176	66	110	—	Working to close a definitive farmout agreement and evaluating both domestic and export development concepts for this 2010 natural gas discovery. In addition, the Leviathan licenses were recently converted to Production and Development Leases.
Leviathan-1 Deep	75	48	27	—	Well did not reach the target interval; we are developing future drilling plans to test this deep oil concept
Dalit	24	2	2	20	Submitted a development plan to the government to develop this 2009 natural gas discovery as a tie-in to existing infrastructure
Dolphin 1	23	1	22	—	Reviewing regional development scenarios for this 2011 natural gas discovery
Offshore Cyprus					
Cyprus A-1	79	22	57	—	Planning additional appraisal activities, including interpretation of seismic data and spudding another exploration well to further refine the ultimate recoverable resources and optimize field development planning.
Falkland Islands					
Scotia	74	74	—	—	Preparing to analyze recently acquired seismic data
Other					
Projects less than $10 million	49	39	4	6	Continuing to drill and evaluate appraisal wells

Total	$830	$370	$304	$156

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Note 9. Asset Retirement Obligations
Asset retirement obligation (ARO) consists primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in ARO are as follows:

	Three Months Ended March 31,	
(millions)	2014	2013
Asset Retirement Obligations, Beginning Balance	$586	$402
Liabilities Incurred	1	1
Liabilities Settled	(14)	(10)
Revision of Estimate	72	(1)
Accretion Expense [1]	10	7
Asset Retirement Obligations, Ending Balance	$655	$399

[1] Accretion expense is included in DD&A expense in the consolidated statements of operations.
Liabilities settled in 2014 include $24 million for onshore US and deepwater Gulf of Mexico abandonments and $17 million related to properties classified as held for sale, offset by $27 million as a result of reclassifying remaining North Sea assets from held for sale to held and used.
Liabilities settled in 2013 relate primarily to non-core onshore US properties that were sold. See Note 3. Divestitures.
Revision in estimate for 2014 includes an increase of $67 million related to a non-operated North Sea field due to an increase in costs and a change in timing. See Note 4. Asset Impairments.

Note 10. Earnings Per Share
Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock include the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust (when dilutive). The following table summarizes the calculation of basic and diluted earnings per share:

	Three Months Ended March 31,	
(millions, except per share amounts)	2014	2013
Income from Continuing Operations	$200	$232
Weighted Average Number of Shares Outstanding, Basic	360	358
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	5	4
Weighted Average Number of Shares Outstanding, Diluted	365	362
Earnings from Continuing Operations Per Share, Basic	$0.56	$0.65
Earnings from Continuing Operations Per Share, Diluted	0.55	0.64
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	6	5

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Note 11. Income Taxes
The income tax provision relating to continuing operations consists of the following:

	Three Months Ended March 31,	
(millions)	2014	2013
Current	$60	$36
Deferred	17	50
Total Income Tax Provision	$77	$86
Effective Tax Rate	27.6 %	27.1 %

Our effective tax rate (ETR) for the first three months of 2014 remained relatively unchanged as compared with the first three months of 2013.
In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2010, Equatorial Guinea – 2008, Israel – 2009 and China –2010.
See Note 3. Divestitures for income taxes associated with discontinued operations.

Note 12. Segment Information
We have operations throughout the world and manage our operations by country. The following information is grouped into four components that are all in the business of crude oil and natural gas exploration, development, production, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, and Sierra Leone); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes China, the North Sea, Falkland Islands, Nicaragua and new ventures. The North Sea geographical segment is included in continuing operations in 2014 and discontinued operations in 2013.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended March 31, 2014					
Revenues from Third Parties	$1,327	$842	$323	$112	$50
Income from Equity Method Investees	52	—	52	—	—
Total Revenues	1,379	842	375	112	50
DD&A	425	308	76	14	27
Asset Impairments	97	5	—	—	92
Income (Loss) from Continuing Operations Before Income Taxes	277	183	261	77	(244)
Three Months Ended March 31, 2013					
Revenues from Third Parties	$1,083	$716	$273	$51	$43
Income from Equity Method Investees	60	—	60	—	—
Total Revenues	1,143	716	333	51	43
DD&A	366	266	54	28	18
Asset Impairments	—	—	—	—	—
Income (Loss) from Continuing Operations Before Income Taxes	318	243	231	15	(171)
March 31, 2014					
Total Assets	$20,192	$13,569	$3,193	$2,822	$608
December 31, 2013					
Total Assets	19,598	13,094	3,199	2,753	552

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Note 13. Commitments and Contingencies
CONSOL Carried Cost Obligation In accordance with our Marcellus Shale joint venture arrangement with a subsidiary of CONSOL Energy Inc. (CONSOL), we agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs, capped at $400 million each year, up to approximately $2.1 billion (CONSOL Carried Cost Obligation).
The CONSOL Carried Cost Obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. Due to low natural gas prices, the CONSOL Carried Cost Obligation has been suspended since the end of 2011. However, due to recent increases in Henry Hub natural gas prices, we began funding a portion of CONSOL's working interest share of certain drilling and completion costs as of March 1, 2014. Based on the March 31, 2014 NYMEX Henry Hub natural gas price curve and current development plans, we forecast funding approximately $235 million in 2014.
Marcellus Shale Firm Transportation Agreements In February 2014, we signed Precedent Agreements for Firm Transportation (the Agreements) to flow 150,000 MMBtu per day of our Marcellus Shale natural gas production to Gulf Coast markets. The Agreements are for transportation services on new pipeline extensions, to be constructed by, and connecting to, an existing third-party system. The pipeline extensions are expected to be complete and operational in June of 2017. Our financial commitment totals approximately $765 million, undiscounted, over a 15-year period. The Agreements are subject to various conditions, including regulatory approval of the pipeline extension projects.
Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. We use common industry terms, such as thousand barrels of oil equivalent per day (MBoe/d) and million cubic feet equivalent per day (MMcfe/d), to discuss production and sales volumes. Our MD&A is presented in the following major sections:

- Executive Overview;
- Operating Outlook;
- Results of Operations; and
- Liquidity and Capital Resources.

The preceding consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with our MD&A.

EXECUTIVE OVERVIEW

We are a worldwide producer of crude oil and natural gas. We aim to achieve sustainable growth in value and cash flow through exploration success and the development of a high-quality, diversified, portfolio of assets with investment flexibility between: onshore unconventional developments and offshore organic exploration leading to major development projects; US and international development projects; and production mix among crude oil, natural gas, and NGLs. We currently focus our efforts in five core operating areas: the DJ Basin and Marcellus Shale (onshore US), deepwater Gulf of Mexico, offshore West Africa, and offshore Eastern Mediterranean, where we have strategic competitive advantage and which we believe generate superior returns. We also seek to enter potential new core areas, and we are currently conducting exploratory activities in domestic and international locations such as Northeast Nevada, the Falkland Islands, Cameroon, and Cyprus.

Our financial results for first quarter 2014 included:

- net income of $200 million as compared with $261 million for first quarter 2013;
- loss on commodity derivative instruments of $75 million (including $42 million non-cash portion of loss) as compared with a loss on commodity derivative instruments of $72 million (including $79 million non-cash portion of loss) for first quarter 2013;
- asset impairment charges of $97 million, as compared with zero for first quarter 2013;
- diluted earnings per share of $0.55, as compared with $0.72 for first quarter 2013;
- cash flow provided by operating activities of $929 million, as compared with $705 million for first quarter 2013;
- ending cash balance of $1.4 billion, as compared with $1.1 billion at December 31, 2013;
- capital spending, on a cash basis, of $1.2 billion, as compared with $806 million for first quarter 2013;
- total liquidity of $4.9 billion at March 31, 2014, as compared with $5.1 billion at December 31, 2013; and
- ratio of debt-to-book capital of 36% at March 31, 2014, as compared with 35% at December 31, 2013.

Our operating results for first quarter 2014 included:

- total sales volumes of 286 MBoe/d, as compared with 246 MBoe/d for the first quarter of 2013;
- delivered record horizontal production of 100 MBoe/d on average from the DJ Basin and Marcellus Shale plays, up over 60% versus first quarter 2013;
- performed completion operations on initial vertical well in the Wilson play of Northeast Nevada, successfully recovering oil from multiple intervals;
- apparent high bidder on 12 deepwater lease blocks in the central Gulf of Mexico Lease Sale 231;
- signed first two regional export sales agreements for natural gas sales from Tamar and Leviathan to customers in Jordan and Palestine;
- finalized agreement with the Israel Antitrust Authority; and
- executed sales agreements to divest of our non-core Haynesville and Powder River Basin assets onshore US.

Exploration Program Update

We have numerous exploration opportunities remaining in our core areas and are also engaged in new venture activity in both our US and international locations.

We were in the process of drilling and/or evaluating significant exploratory wells at March 31, 2014 (See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs), and expect to continue an active exploratory drilling program in the future.

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A significant portion of our 2014 capital investment program is dedicated to exploration and associated appraisal activities, including leasehold acquisitions. However, we do not always encounter hydrocarbons through our drilling activities. In addition, we may find hydrocarbons but subsequently reach a decision, through additional analysis or appraisal drilling, that a development project is not economically or operationally viable.

In the event we conclude that one of our exploratory wells did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. Additionally, we may not be able to conduct exploration activities prior to lease expirations. As a result, in a future period, dry hole cost and/or leasehold abandonment expense could be significant. See Operating Outlook – Potential for Future Asset Impairment, Dry Hole or Lease Abandonment Expense, below.

Updates on significant exploration activities are as follows:

Northeast Nevada   We are evaluating drilling and completion results from our first exploratory vertical wells. We plan to begin flow testing the first well in second quarter 2014 and drill additional exploratory wells later in 2014.

Deepwater Gulf of Mexico   During first quarter 2014, we participated in the central Gulf of Mexico Lease Sale 231 and were apparent high bidder on 12 deepwater blocks, providing further opportunities to expand our exploration portfolio. In late March 2014, we spud the Katmai exploration well (Green Canyon Block 40, 50% operated working interest).

Also during the quarter, the new Atwood Advantage drillship successfully mobilized to the Gulf of Mexico where it is undergoing readiness activities for our 2014 drilling plan.

Offshore West Africa We plan to shoot 3D seismic tests across Blocks O and I, offshore Equatorial Guinea, during the second half of 2014, and drill an exploratory well offshore Cameroon in the fourth quarter of 2014. Additionally, we are reprocessing 3D seismic data over our YoYo mining concession, offshore Cameroon.

Offshore Eastern Mediterranean   We are processing and evaluating recently acquired 3D seismic data over offshore Israel and Cyprus and continue to study locations for potential exploratory wells, with opportunities offshore both Israel and Cyprus.

Offshore Falkland Islands We continue to process and evaluate 3D seismic data over the northern and southern areas and prepare for our first operated exploratory well.

Major Development Project Updates

We continue to advance our major development projects, which we expect to deliver incremental production over the next several years. Updates on major development projects are as follows:

Sanctioned Ongoing Development Projects

A "sanctioned" development project is one for which a final investment decision has been made.

DJ Basin (Onshore US)   We continue to operate at a high level of horizontal drilling activity with continued growth from strong well performance, new wells brought online, and expanded natural gas and crude oil infrastructure. During the quarter, we spud 54 standard length lateral wells and 13 extended reach lateral wells, and recently increased our 2014 drilling program to include over 90 extended reach lateral wells. Currently, 10 drilling rigs are active across the basin.

Marcellus Shale (Onshore US)   We continue to delineate the wet gas acreage, while our partner, CONSOL Energy, Inc. (CONSOL), continues to develop the dry gas and progress the Allegheny County Airport areas. During the quarter, we and our partner drilled 36 wells, and 11 wells initiated production. The joint venture is currently operating nine drilling rigs.

Due to an increase in Henry Hub natural gas prices, our funding of certain drilling and completion costs under the CONSOL Carried Cost Obligation commenced as of March 1, 2014 . See Liquidity and Capital Resources – Contractual Obligations below.

Gunflint (Deepwater Gulf of Mexico)   In 2013, we sanctioned the development plan for the 2008 Gunflint crude oil discovery, utilizing a subsea tieback to an existing host facility, and are targeting first production in 2016.

Big Bend (Deepwater Gulf of Mexico) The 2012 Big Bend crude oil discovery is located in the Rio Grande area of the deepwater Gulf of Mexico. In October 2013, we sanctioned a development plan, utilizing a subsea tieback to a third party host facility. During first quarter 2014, using the Ensco 8501 drilling rig, we conducted well completion activities, and first production is targeted for late 2015.

Tamar Expansion (Offshore Israel) The Tamar compression project, which is expected to increase capacity by 200 MMcf/d at the Ashdod onshore terminal, is progressing, and we expect operational start-up in the second half of 2015.

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Tamar Southwest (Offshore Israel) We anticipate first production in the second half of 2015 utilizing Tamar infrastructure as part of our expansion project to meet domestic demand. We also expect Tamar Southwest to provide flow rate assurance for the overall Tamar project.

Unsanctioned Development Projects (As of March 31, 2014)

Dantzler (Deepwater Gulf of Mexico) The 2013 Dantzler crude oil discovery is located in the Rio Grande area of the deepwater Gulf of Mexico and is a co-development opportunity with Big Bend. We plan to drill another Dantzler appraisal well later in the year.

Leviathan (Offshore Israel) We continue to make progress towards sanctioning the first phase of Leviathan development. In February 2014, we signed a non-binding memorandum of understanding (MOU) regarding the sale of an interest in the Leviathan licenses to Woodside Petroleum (Woodside). All the existing Leviathan partners are participating as sellers of a 25% interest to Woodside. We agreed to convey a 9.66% working interest and will continue as upstream operator with a 30% working interest. We and our existing Leviathan partners continue to work with Woodside to close a definitive agreement. Following completion of the transaction, Woodside will become operator of any LNG development of the field.

Total compensation to us is anticipated to include $525 million in cash payments as follows:

- an initial cash payment of $390 million payable at closing of the transaction, which is expected later in 2014; and
- a second cash payment of $135 million which is due when a final investment decision is made in relation to an LNG or FLNG development program or as regional export contracts are executed in excess of a threshold volume amount, whichever occurs earlier.

In addition, the MOU provides for Woodside to share a portion of certain of their future revenues, subject to caps, if specified events were to occur, including: reaching a certain level of natural gas export, an increase in ultimate recoverable resources (as defined), or a commercial crude oil discovery and subsequent development.

The MOU includes the agreed-upon commercial terms of the farm-out transaction. The transaction remains subject to the execution of definitive agreements between the parties, as well as necessary and customary regulatory approvals.

In March 2014, the Israeli government converted the Leviathan licenses to Production and Development Leases (Leases). The Leases provide for, among other things:

- 30-year terms, from February14, 2014 until February 13, 2044;
- the right to develop the project giving priority to the domestic natural gas market and requiring a connection to the domestic natural gas transmission system prior to export; and
- targeted milestones for development, subject to timing of regulatory and permitting requirements, natural gas sales agreements and financing.

See also Update on Israel's Natural Gas Economy, below.

Cyprus Project (Offshore Cyprus) We are planning additional appraisal activities, including interpretation of seismic data and spudding another exploration or appraisal well to further determine the ultimate recoverable resources on Block 12 and optimize field development planning. In addition, we have filed an application for renewal of the production sharing contract for two additional years.

Diega and Carla (Offshore Equatorial Guinea) We are currently evaluating regional development scenarios and targeting to sanction a Diega development project in 2014, with first production targeted for early 2017.

See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs for additional information on costs incurred related to these projects.

Non-Core Divestiture Program

Our non-core asset divestiture program is winding down with certain smaller onshore US property packages sold during first quarter 2014 or expected to be sold this year. We are also in the process of negotiating a sale of our China assets. Divestitures of non-core properties allow us to allocate capital and employee resources to high-value and high-growth areas. See Item 1. Financial Statements – Note 3. Divestitures and Operating Outlook - Potential for Future Asset Impairment, Dry Hole or Lease Abandonment Expense, below.

We are currently winding up local business activities in Argentina, Ecuador, and certain North Sea jurisdictions. At this time, we do not believe that any of the activities associated with these areas will have a material effect on our financial position, results of operations or cash flows.

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Update on Israel's Natural Gas Economy

Israel Antitrust Authority We and our partners recently reached an agreement with the Israeli government on various antitrust matters. As a result of the agreement, we will divest two natural gas discoveries. We have initiated an active program to locate a buyer and other actions required to complete the plan to sell the assets. The assets are reported within assets held for sale in our consolidated balance sheet at March 31, 2014.

The agreement also granted the rights, to us and our partners, to jointly market natural gas from the Leviathan field. As a result, we plan to further our domestic natural gas marketing activities. The agreement is subject to final approval by the Israeli government.

On March 26, 2014, the Israel Ministry of Finance (Ministry) issued a memorandum indicating its intent to amend the Petroleum Profits Law in light of the Israeli government's 2013 decision to permit the export of natural gas from Israel. The purpose of the proposed amendments is to regulate the method of taxing petroleum export transactions, and, in particular, exports of natural gas. As a part of the Ministry's final recommendation, several methodologies could be used to establish the transfer price for natural gas sales, depending on various circumstances. We are currently evaluating the recommendation and proposed amendments.

Update on Hydraulic Fracturing

Potential Rulemaking Although hydraulic fracturing is regulated primarily at the state level, governments and agencies at all levels from federal to municipal are conducting studies and considering regulations, and some have proposed rules.

In 2013, several communities in Colorado passed ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries. The large majority of our DJ Basin acreage is not located in these municipalities and, therefore, we do not expect our operations to be impacted by these specific developments.

In advance of the upcoming November 2014 state-wide elections, three general types of ballot initiatives have now emerged in Colorado. They can be characterized as:

- initiatives relating to local government control;
- initiatives relating to mandatory statewide drilling setbacks; and
- initiatives relating to constitutional duties to protect the environment.

Should these, or other, Colorado ballot initiatives succeed in regulating, limiting or banning hydraulic fracturing or other facets of oil and gas exploration, development or operations, our business could be impacted resulting in delay or inability to develop certain oil and gas reserves, reducing our long-term reserves, production and cash flow growth, and have a potential negative impact on our stock price.

In Nevada, the State Assembly recently adopted legislation that requires the development of a program to regulate the use of hydraulic fracturing in Nevada. State regulators are in the process of proposing rules and holding public hearings.

We will continue to monitor new and proposed legislation and regulations to assess the potential impact on our operations. We are currently evaluating the possible impact any proposed rules, such as those described above, could have on our business. Any additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

Concurrently, we are engaged in extensive public education and outreach efforts with the goal of engaging and educating the general public about the energy, economic and environmental benefits of safe and responsible oil and natural gas development.

Regulations

On February 23, 2014, the Colorado Air Quality Control Commission (Commission) adopted a number of revisions to its oil and gas industry regulations. The revisions include the full adoption of EPA's Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (also known as NSPS Quad O) with corresponding complementary control measures. The control measures set forth requirements for identifying and repairing leaks, undertaking record keeping, and submitting reports. The revisions also include the first ever regulation of methane emissions from the industry. In collaboration with the Environmental Defense Fund and other oil and gas operators, we provided testimony and evidence to the Commission in support of the adopted revisions. The adopted revised regulations were published in the Colorado Register on March 25, 2014, Volume 37, No. 6, and are effective as of April 14, 2014. Copies of these regulations are available at http://www.sos.state.co.us/CCR. We do not currently believe costs incurred to implement these regulations will be material to our earnings or cash flows.

Sales Volumes

The execution of our strategy has delivered a diversified production growth most recently due to our Tamar natural gas field and Alen condensate project coming online in 2013 along with accelerated activity in onshore US unconventional

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developments. On a BOE basis, total sales volumes were 16% higher for the first quarter of 2014 as compared with the first quarter of 2013, and our mix of sales volumes was 45% global liquids, 27% international natural gas, and 28% US natural gas. See Results of Operations – Revenues, below.

Commodity Price Changes

Average realized natural gas prices increased 45% in the US and 9% in Israel for first quarter 2014 as compared with the first quarter of 2013. Average realized crude oil prices remained relatively unchanged in the US, and decreased 5% for Equatorial Guinea.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2014 Production   Our expected crude oil, natural gas and NGL production for 2014 may be impacted by several factors including:

- changes to drilling plans in the DJ Basin and the Marcellus Shale;
- Israeli demand for electricity, which affects demand for natural gas as fuel for power generation and industrial market growth, and which is impacted by unseasonable weather;
- potential downtime at key assets including: Galapagos and Swordfish, deepwater Gulf of Mexico; Tamar, offshore Israel; and Aseng and Alen offshore Equatorial Guinea;
- natural field decline in the deepwater Gulf of Mexico, non-core onshore US areas, and the Alba and Aseng fields offshore Equatorial Guinea; and
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico or flooding in the DJ Basin, Marcellus Shale and/or Rocky Mountain areas, which can shut-in or reduce production or result in the use of produced natural gas to fuel burners.

2014 Capital Investment Program Total capital expenditures are estimated at $4.8 to $5.0 billion for 2014. We expect to invest approximately 70% of the program in onshore US development and approximately 30% of the program in global deepwater activities.

The 2014 capital investment program is estimated to exceed operating cash flows and is expected to be funded from cash flows from operations, cash on hand, and borrowings under our unsecured revolving Credit Facility (Credit Facility) and/or other financing. Funding may also be provided by proceeds from divestment of non-core assets or farm-out of working interests in exploration prospects. See Liquidity and Capital Resources – Financing Activities.

We will continue to evaluate the level of capital spending and remain flexible throughout the year. For further discussion, see Executive Overview – Update on Hydraulic Fracturing, above, regarding potential legislative or regulatory changes in the use of hydraulic fracturing, and Liquidity and Capital Resources – Contractual Obligations, below, regarding the CONSOL Carried Cost Obligation.

Potential for Future Asset Impairment, Dry Hole or Lease Abandonment Expense

Exploration Activities We have an active exploratory drilling program. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. For example, in the Falkland Islands we are processing recently acquired seismic data. We will conduct seismic interpretation and basin modeling during the remainder of 2014 in order to determine our future drilling program. Integration of seismic information with the results of the Scotia exploratory well will allow us to assess the economic viability of this prospect. If we were to determine, based on the results of seismic interpretation and/or additional drilling activities, that the Scotia prospect is not economically viable, the costs we have incurred (approximately $72 million to date) would be written off to dry hole expense.

Additionally, we may not conduct exploration activities prior to lease expirations. For example, in the deepwater Gulf of Mexico, while we continue to mature our prospect portfolio, regulations have become more stringent due to the Deepwater Horizon incident in 2010. In some instances, specifically engineered blowout preventers, rigs, and completion equipment may be required for high pressure environments. Regulatory requirements or lack of readily available equipment could prevent us from engaging in future exploration activities during our current lease terms.

One particular deepwater Gulf of Mexico lease, which we acquired based on regulations in effect prior to the Deepwater Gulf of Mexico Moratorium, is set to expire on July 31, 2014. We intend to request an extension of this lease; however, there is no certainty an extension will be obtained prior to the lease expiration. The lease had a net book value of approximately $41 million at March 31, 2014. If we are unable to obtain an extension, we must relinquish the lease, abandon our exploration plans, and write off the book value to exploration expense.

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Producing Properties Commodity prices remain volatile. A decline in future crude oil or natural gas prices could result in impairment charges. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production along with operating and development costs, market outlook on forward commodity prices, and interest rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward crude oil or natural gas prices alone could result in an impairment.

Occasionally, well mechanical problems arise, which can reduce production and potentially result in reductions in proved reserves estimates. For example, our South Raton development in the deepwater Gulf of Mexico is currently shut-in due to mechanical issues. We are preparing for remediation work to commence in second quarter 2014 and expect return to production by third quarter 2014. No impairment is currently indicated; however, we will monitor production and reserves when South Raton is brought back online and continue to assess the field for possible impairment. South Raton had a net book value of approximately $121 million at March 31, 2014.

In addition, well decommissioning programs, especially in deepwater or remote locations, are often complex and very expensive. It may be difficult to estimate timing of actual abandonment activities, which are subject to regulatory approval and the availability of rigs and services. It may be difficult to estimate costs as rigs and services become more expensive in periods of high demand. Therefore, our ARO estimates may change, sometimes significantly, and could result in asset impairment. For example, in the first quarter of 2014, the ARO estimate for one of our remaining non-operated North Sea fields changed significantly, resulting in asset impairment charges of $92 million.

Divestments We are currently marketing certain non-core onshore US properties. If properties are reclassified as assets held for sale in the future, they will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell. In addition, we would allocate a portion of goodwill to any non-core onshore US property held for sale that constitutes a business, which could potentially decrease any gain or increase any loss recorded on the sale. Goodwill write-offs result in an increase in our effective tax rate because goodwill is nondeductible for US federal income tax purposes.

In addition, certain assets offshore Israel and offshore China are classified held for sale at March 31, 2014. No impairments are indicated at this time. However, failure to achieve acceptable sale terms or delays in closing sales of these properties could result in impairment and/or loss on sale.

RESULTS OF OPERATIONS

In the discussion below, the North Sea geographical segment is reflected as discontinued operations for the first three months of 2013. During first quarter 2014, the remaining unsold North Sea assets were reclassified to held and used, and their operations are included in continuing operations for first quarter 2014. See Item 1. Financial Statements - Note 2. Basis of Presentation, Note 3. Divestitures, Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures. See also Discontinued Operations, below.

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Revenues

Revenues were as follows:

(millions)	2014	2013	Increase/(Decrease) from Prior Year	
Three Months Ended March 31,				
Oil, Gas and NGL Sales	$1,327	$1,083	23	%
Income from Equity Method Investees	52	60	(13	)%
Total	$1,379	$1,143	21	%

Changes in revenues are discussed below.

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

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2014							
United States	64	483	18	163	$97.02	$4.81	$44.50
Equatorial Guinea (2)	34	242	—	74	105.73	0.27	—
Israel	—	218	—	37	—	5.60	—
Other International (3)	5	—	—	5	104.28	—	—
Total Consolidated Operations	103	943	18	279	100.23	3.83	44.50
Equity Investees (4)	2	—	5	7	104.71	—	74.51
Total Continuing Operations	105	943	23	286	$100.30	$3.83	$51.54
Three Months Ended March 31, 2013							
United States	63	409	16	146	$95.70	$3.31	$39.19
Equatorial Guinea (2)	27	246	—	68	111.79	0.27	—
Israel	—	111	—	19	—	5.15	—
Other International (3)	4	—	—	4	109.22	—	—
Total Consolidated Operations	94	766	16	237	100.90	2.60	39.19
Equity Investees (4)	2	—	6	8	108.63	—	74.19
Total Continuing Operations	96	766	22	245	$101.07	$2.60	$49.29

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

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

(3) Other International primarily includes China.

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

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

(millions)	Sales Revenues Crude Oil & Condensate	Natural Gas	NGLs	Total
Three Months Ended March 31, 2013	$849	$179	$55	$1,083
Changes due to				
Increase in Sales Volumes	85	41	11	137
Increase (Decrease) in Sales Prices	(6)	105	8	107
Three Months Ended March 31, 2014	$928	$325	$74	$1,327

Crude Oil and Condensate Sales – Revenues from crude oil and condensate sales increased during first quarter 2014 as compared with 2013 due to the following:

- higher sales volumes in the DJ Basin attributable to our horizontal drilling program; and
- additional sales volumes of 12 MBoe/d from the Alen condensate project, offshore Equatorial Guinea, which began producing in late second quarter 2013;

partially offset by:

- negative volume impact of severe winter weather and downtime for facility upgrades in the DJ Basin;
- lower sales volumes from the Galapagos project, deepwater Gulf of Mexico, and Aseng project, offshore Equatorial Guinea, due to natural production declines; and
- decreases in total consolidated average realized price related to sales volumes offshore Equatorial Guinea, which are priced based on the global Brent market.

Natural Gas Sales – Revenues from natural gas sales increased during the first quarter of 2014 as compared with 2013 due to the following:

- increases in total consolidated average realized prices of 47% primarily due to increased demand from cooler weather and higher-than-expected inventory withdrawals in the US;
- higher sales volumes in the Marcellus Shale of 206 MMcf/d for first quarter 2014, as compared with 100 MMcf/d for first quarter of 2013, primarily attributable to our horizontal drilling program and continued ramp-up of activity; and
- additional sales volumes offshore Israel due to start up of the Tamar natural gas field, which began producing at the end of first quarter 2013;

partially offset by:

- lower sales volumes due to non-core onshore US properties divested during 2013 and first quarter 2014; and
- lower sales volumes due to natural field decline from the Mari B/Noa/Pinnacles fields, offshore Israel.

NGL Sales – The majority of our US NGL production is currently from the DJ Basin. Additional NGL production from the Marcellus Shale added 2 MBbl/d during first quarter 2014 as compared with 2013, primarily due to increased production from the wet gas acreage. NGL sales in the DJ Basin increased by 1 MBbl/d during the first quarter of 2014 as compared with 2013, and recent sales of our non-core onshore US properties have slightly reduced sales volumes as compared with first quarter 2013. Additionally, sales prices have increased 14% for the first three months of 2014, compared to the first three months of 2013.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities, and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore on Bioko Island in Equatorial Guinea.

Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, our share of dividends is reported within cash flows from operating activities and our share of investments is reported within cash flows from investing activities.

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Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2014	2013	Increase from Prior Year
Three Months Ended March 31,			
Production Expense	$232	$187	24 %
Exploration Expense	74	61	21 %
Depreciation, Depletion and Amortization	425	366	16 %
General and Administrative	140	112	25 %
Asset Impairments	97	—	—
Other Operating (Income) Expense, Net	7	(8)	N/M
Total	$975	$718	36 %

N/M – Amount is not meaningful

Changes in operating costs and expenses are discussed below.

Production Expense   Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	Other Int'l, Corporate
Three Months Ended March 31, 2014						
Lease Operating Expense (2)	$5.79	$145	$88	$31	$12	$14
Production and Ad Valorem Taxes	1.96	49	40	—	—	9
Transportation and Gathering Expense	1.52	38	37	—	—	1
Total Production Expense	$9.27	$232	$165	$31	$12	$24
Three Months Ended March 31, 2013						
Lease Operating Expense (2)	$5.49	$117	$89	$20	$1	$7
Production and Ad Valorem Taxes	2.02	43	34	—	—	9
Transportation and Gathering Expense	1.30	27	27	—	—	—
Total Production Expense	$8.81	$187	$150	$20	$1	$16

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

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

For the first quarter of 2014, total production expense increased as compared with 2013 due to the following:

- an increase in lease operating expense of approximately $10 million in the DJ Basin due to workovers, labor charges and other cost allocations;
- an increase in lease operating expense of $11 million offshore Equatorial Guinea primarily due to the start up of the Alen field in the second half of 2013;
- an increase in lease operating expense of $11 million offshore Israel primarily due to the start up of the Tamar field, which began producing at the end of first quarter 2013;
- an increase in production and ad valorem taxes of approximately $7 million in the DJ Basin due to higher production volumes and higher average prices; and
- an increase in transportation and gathering expense of approximately $8 million in the Marcellus Shale due to increased production from ongoing development activities;

partially offset by:

- a decrease in lease operating expense of approximately $2 million from sales of non-core US onshore properties in 2013; and
- a decrease of approximately $6 million in the deepwater Gulf of Mexico primarily due to lower throughput fees as we recently acquired the Neptune spar to process our remaining Swordfish production.

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Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa [1]	Eastern Mediter-ranean [2]	Other Int'l, Corporate [3]
Three Months Ended March 31, 2014					
Dry Hole Cost	$2	$3	$—	$—	$(1)
Seismic	23	7	—	1	15
Staff Expense	35	8	2	3	22
Other	14	14	—	—	—
Total Exploration Expense	$74	$32	$2	$4	$36
Three Months Ended March 31, 2013					
Dry Hole Cost	$—	$—	$—	$—	$—
Seismic	25	6	—	—	19
Staff Expense	28	7	1	3	17
Other	8	9	—	—	(1)
Total Exploration Expense	$61	$22	$1	$3	$35

(1) West Africa includes Equatorial Guinea, Cameroon, and Sierra Leone.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes various international new ventures such as Falkland Islands and Nicaragua.

Exploration expense for the first quarter of 2014 included:

- $12 million of seismic expense in the Falkland Islands; and
- staff expense associated with new ventures and corporate expenditures.

Exploration expense for the first quarter of 2013 included the following:

- $17 million of 3D seismic in the Falkland Islands; and
- staff expense associated with new ventures and corporate expenditures.

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

	Three Months Ended March 31, 2014	2013
DD&A Expense (millions) [1]	$425	$366
Unit Rate per BOE [2]	$16.95	$17.18

(1) For DD&A expense by geographical area, see Item 1. Financial Statements – Note 12. Segment Information.

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

Total DD&A expense for the first quarter of 2014 increased as compared with 2013 due to the following:

- increases of $19 million in the DJ Basin and $14 million in the Marcellus Shale due to higher sales volumes associated with increased development activity;
- an increase of $9 million in the deepwater Gulf of Mexico due to a new well producing at Ticonderoga and the addition of the Neptune spar at Swordfish;
- an increase of $22 million offshore Equatorial Guinea primarily due to the start up of the Alen field in the second half of 2013; and
- an increase of approximately $12 million related to the start up of the Tamar field, offshore Israel, at the end of first quarter 2013;

partially offset by:

- a decrease of $7 million due to sales of non-core US onshore properties in 2013; and
- a decrease of approximately $27 million related to the Mari-B/Noa/Pinnacles fields due to natural field decline.

The reduction in the unit rate per BOE for first quarter 2014 as compared with 2013 was due primarily to lower cost volumes produced at Tamar, offshore Israel, which replaced higher cost volumes produced from the Mari-B/Noa/Pinnacles fields. In addition, the effect of higher costs incurred in the DJ Basin and Marcellus Shale were offset by the effect of a higher volume of proved reserves being recorded at year-end 2013 as compared with year-end

2012.

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

	Three Months Ended March 31,	
	2014	2013
G&A Expense (millions)	$140	$112
Unit Rate per BOE [1]	$5.57	$5.28

[1] Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

G&A expense for the first quarter of 2014 increased as compared with 2013 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities. For example, our total number of employees increased 15%, from 2,190 at December 31, 2012, to 2,527 at December 31, 2013.

Asset Impairment Expense Asset impairment expense was as follows:

	Three Months Ended March 31,	
(millions)	2014	2013
Asset Impairments	$97	$—

Asset impairment expense related primarily to one of our remaining non-operated North Sea fields. See Item 1. Financial Statements – Note 2. Basis of Presentation, Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures.

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended March 31,	
(millions)	2014	2013
Loss on Commodity Derivative Instruments	$75	$72
Interest, Net of Amount Capitalized	47	25
Other Non-Operating (Income) Expense, Net	5	10
Total	$127	$107

Loss on Commodity Derivative Instruments Loss on commodity derivative instruments is a result of mark-to-market accounting. Many factors impact a gain or loss on commodity derivative instruments including: increases and decreases in the commodity forward curves compared to our executed hedging arrangements; increases in hedged future volumes; and the mix of hedge arrangements between NYMEX WTI, Dated Brent and NYMEX HH commodities. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

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

	Three Months Ended March 31,	
	2014	2013
(millions, except unit rate)		
Interest Expense, Gross	$81	$67
Capitalized Interest	(34)	(42)
Interest Expense, Net	$47	$25
Unit Rate per BOE [1]	$1.89	$1.19

[1] Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

The increase in interest expense, gross, is due to an increase in new senior debt issued in November 2013 and recent borrowings under the Credit Facility.

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The decrease in capitalized interest is primarily due to the completion of major projects, such as Alen, offshore West Africa, and Tamar, offshore Israel, partially offset by higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and offshore Israel.

Income Tax Provision

See Item 1. Financial Statements – Note 11. Income Taxes for a discussion of the change in our effective tax rate for the first quarter of 2014 as compared with 2013.

Discontinued Operations

Summarized results of discontinued operations were as follows:

	Three Months Ended March 31, 2013
(millions)	
Oil and Gas Sales	$10
Expenses	11
Income Before Income Taxes	(1)
Income Tax Expense	7
Operating Loss, Net of Tax	(8)
Gain on Sale, Net of Tax	37
Income From Discontinued Operations	$29
Key Statistics:	
Daily Production	
Crude Oil & Condensate (MBbl/d)	1
Natural Gas (MMcf/d)	3
Average Realized Price	
Crude Oil & Condensate (Per Bbl)	$113.97
Natural Gas (Per Mcf)	10.03

Our long-term debt is recorded at the consolidated level and is not reflected by each component. Thus, we have not allocated interest expense to discontinued operations. See Item 1. Financial Statements – Note 3. Divestitures.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our discovered hydrocarbons, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the volatile commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a robust exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity.

We endeavor to maintain an investment grade debt rating in service of these objectives, while delivering competitive returns and a growing dividend. We utilize a commodity price hedging program to reduce the impacts of commodity price volatility and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and the funding of our business.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash flows from operations, cash on hand, available borrowing capacity under our Credit Facility, and proceeds from sales of non-core properties. We may also access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Credit Facility or to refinance scheduled debt maturities. On April 15, 2014, we repaid $200 million of scheduled current maturities. See Item 1. Financial Statements – Note 6. Debt and Credit Facility, below.

Expanded development in the DJ Basin and Marcellus Shale, investment in our recently sanctioned major development projects, and our planned exploration and appraisal drilling activities are estimated to result in near term capital expenditures exceeding cash flows from operating activities. The extent to which capital investment will exceed operating cash flows depends on our success in sanctioning future development projects, the results of our exploration activities, and new business opportunities as well as external factors such as commodity prices, among others. Our financial capacity, coupled with our

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

To support our investment program, we expect that higher production resulting from our core onshore US development programs combined with new production from Tamar, which began producing in late first quarter 2013, and Alen, which began producing in late second quarter 2013, will result in an increase in cash flows which will be available to meet a substantial portion of future capital commitments.

Cash on hand at March 31, 2014 totaled $1.4 billion, and includes both domestic and foreign cash. We consider repatriating foreign cash to increase our financial flexibility and fund our capital investment program to the extent such cash is not required to fund foreign investment projects and we would not incur additional US tax. During first quarter 2014, we repatriated $62 million from our UK operations. During April 2014, we repatriated an additional $110 million from our UK operations. We incurred no residual US tax on these repatriations.

We also evaluate potential strategic farm-out arrangements of our working interests in Israel, Cyprus, Cameroon, Nicaragua and the deepwater Gulf of Mexico for reimbursement of our capital spending in these areas. In addition, our current liquidity level and balance sheet, along with our ability to access the capital markets, provide flexibility. We believe that we are well-positioned to fund our long-term growth plans.

We are currently evaluating potential development scenarios for our significant natural gas discoveries offshore Eastern Mediterranean, including Leviathan and Cyprus Block 12. The magnitude of these discoveries presents technical and financial challenges for us due to the large-scale development requirements. Potential development scenarios may include the construction of subsea pipeline, floating LNG, LNG terminals, FPSO or other options. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. We and our Leviathan partners have announced a potential strategic partner for Leviathan, Woodside, who could provide midstream expertise as well as LNG project execution, marketplace expertise and financial capacity.

Marcellus Shale Joint Venture Our joint venture arrangement with a subsidiary of CONSOL Energy, Inc. is structured in a manner to address partner alignment and financial affordability. Under the arrangement, we agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs up to a fixed amount. See Contractual Obligations, below.

Pension Plan Termination We are in the process of terminating our defined benefit pension plan. We expect to liquidate the associated pension obligation through lump-sum payments to participants. In addition, we amended our restoration plan effective December 31, 2013 to freeze the accrual of benefits under the plan in coordination with the termination of our defined benefit pension plan so that no additional benefits will accrue under the restoration plan after December 31, 2013. Benefits accrued under the restoration plan as of that date will be frozen, and payments under the restoration plan will continue to be made in ordinary course without acceleration of payment. Participants in the restoration plan who remain employed by us upon final liquidation and distribution of assets of the defined benefit pension plan may elect to have the lump sum present value of their restoration plan benefits converted into an account balance under our nonqualified deferred compensation plan.

As of December 31, 2013, the latest actuarial measurement date for the plans, the accumulated benefit obligations for the defined benefit pension and restoration plans totaled approximately $394 million, and the fair value of plan assets was $265 million, leaving approximately $129 million unfunded. At March 31, 2014, we reclassified the long-term portion of the net pension plan liability ($50 million) to current, as we expect final plan termination to occur by the end of first quarter 2015. We expect to make additional contributions to the plans during the period leading up to final termination and distribution to the extent necessary to fund these obligations.

In addition, upon pension and restoration plan termination, all unamortized prior service cost and net actuarial loss remaining in AOCL will be charged to expense. These amounts totaled approximately $101 million for the pension plan and $38 million for the restoration plan at March 31, 2014.

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Available Liquidity Information regarding cash and debt balances is as follows:

(millions, except percentages)	March 31, 2014	December 31, 2013
Cash and Cash Equivalents	$1,354	$1,117
Amount Available to be Borrowed Under Credit Facility (1)	3,550	4,000
Total Liquidity	$4,904	$5,117
Total Debt (2)	$5,285	$4,843
Total Shareholders' Equity	9,361	9,184
Ratio of Debt-to-Book Capital (3)	36 %	35 %

(1) See Credit Facility, below.

(2) Total debt includes capital lease and other obligations and excludes unamortized debt discount.

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

Cash and Cash Equivalents We had approximately $1.4 billion in cash and cash equivalents at March 31, 2014, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $1.0 billion of this cash is attributable to our foreign subsidiaries and a portion would be subject to US income taxes if repatriated.

Credit Facility Our Credit Facility matures on October 3, 2018. The commitment is $4.0 billion through the maturity date of the Credit Facility. As of March 31, 2014, we had drawn $450 million under the Credit Facility at an interest rate of 1.43%. Borrowings under our Credit Facility subject us to interest rate risk. See Item 1. Financial Statements –Note 6. Debt and Item 3. Quantitative and Qualitative Disclosures.

Commodity Derivative Instruments We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments may include variable to fixed price commodity swaps, two-way collars, and/or three-way collars.

Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. We net settle by counterparty based on netting provisions within the master agreements. 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, 2014, the fair value of our commodity derivative assets was $11 million and the fair value of our commodity derivative liabilities was $111 million (after consideration of netting provisions within our master agreements). See Item 1. Financial Statements –Note 7. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of commodity derivative instruments and Credit Risk, below.

Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedging counterparties, and financial institutions on an ongoing basis. Some of these entities are not as creditworthy as we are and may experience credit downgrades or liquidity problems. Counterparty credit downgrades or liquidity problems could result in a delay in our receiving proceeds from commodity sales, reimbursement of joint venture costs, and potential delays in our major development projects. We are unable to predict sudden changes in a party's creditworthiness or ability to perform. Even if we do accurately predict such sudden changes, our ability to negate these risks may be limited and we could incur significant financial losses.

In addition, nonoperating partners often must obtain financing for their share of capital cost for development projects. A partner's inability to obtain financing could result in a delay of our joint development projects. For example, our Eastern Mediterranean partners must obtain financing for their share of significant development expenditures at Leviathan, offshore Israel, which potentially includes an LNG project and/or major underwater pipeline. We are considering assisting our current Leviathan partners, under certain conditions, to obtain appropriate financing for their share of development costs.

Credit enhancements have been obtained from some parties in the form of parental guarantees, letters of credit or credit insurance; however, not all of our counterparty credit is protected through guarantees or credit support. Nonperformance by a trade creditor, joint venture partner, hedging counterparty or financial institution could result in significant financial losses.

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Contractual Obligations

CONSOL Carried Cost Obligation The CONSOL Carried Cost Obligation represents our agreement to fund up to approximately $2.1 billion of CONSOL’s future drilling and completion costs. The CONSOL Carried Cost Obligation is expected to extend over a multi-year period and is capped at $400 million in each calendar year. The obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices. Due to past low natural gas prices, the CONSOL Carried Cost Obligation was suspended from the end of 2011 to February 28, 2014. Due to recent increases in Henry Hub natural gas prices, we began funding a portion of CONSOL's working interest share of certain drilling and completion costs as of March 1, 2014. Based on the March 31, 2014, NYMEX Henry Hub natural gas price curve and current development plans, we forecast funding approximately $235 million in 2014. The carry will be suspended again if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any future three consecutive month period.

Marcellus Shale Firm Transportation Agreements In February 2014, we signed Precedent Agreements for Firm Transportation to move 150,000 MMBtu per day of our Marcellus Shale natural gas production to Gulf Coast markets. Our financial commitment is approximately $765 million, undiscounted, over a 15-year period, beginning in 2017.

Cash Flows

Cash flow information is as follows:

	Three Months Ended March 31,	
	2014	2013
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$929	$705
Investing Activities	(1,078)	(748)
Financing Activities	386	(39)
Increase (Decrease) in Cash and Cash Equivalents	$237	$(82)

Operating Activities   Net cash provided by operating activities for the first three months of 2014 increased as compared with 2013. Higher natural gas sales prices and an increase in crude oil and natural gas sales volumes were offset by slightly lower crude oil sales prices and increases in production expenses and general and administrative expense. Working capital changes contributed $126 million of positive operating cash flow in first quarter 2014 as compared with a negative impact of $9 million in first quarter 2013.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions, including farm-in arrangements, which may result in reimbursement for capital spending that had occurred in prior periods. Capital spending for property, plant and equipment increased by $352 million during the first three months of 2014 as compared with 2013, primarily due to increased major project development activity in our core areas. We also invested $12 million in CONE Gathering LLC (CONE), discussed below, during the first three months of 2014. We received $92 million proceeds from non-core asset divestitures first quarter 2014, as compared with $76 million during the same period in 2013.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first three months of 2014, funds were provided by cash proceeds from, and tax benefits related to the exercise of stock options ($16 million) and net cash proceeds from our Credit Facility ($450 million). We used cash to pay dividends on our common stock ($50 million), make principal payments related to capital lease obligations ($15 million) and repurchase shares of our common stock ($15 million).

In comparison, during the first three months of 2013, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($31 million). We also used cash to pay dividends on our common stock ($44 million), make principal payments related to the Aseng FPSO capital lease obligation ($12 million) and repurchase

shares of our common stock ($14 million).
See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

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Investing Activities

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

	Three Months Ended March 31,	
	2014	2013
(millions)		
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition [1]	$55	$37
Exploration	90	188
Development [2]	747	630
Corporate and Other	47	35
Total	$939	$890
Other		
Investment in Equity Method Investee [3]	$12	$20
Increase in Capital Lease Obligations	5	—

(1) Unproved property acquisition cost for 2014 includes $20 million in the DJ Basin and $35 million in the Marcellus Shale. Unproved property acquisition cost for 2013 includes $27 million in the DJ Basin and $9 million in the Marcellus Shale.

(2) Development expenditures for 2014 include drilling rig mobilization charges of $45 million, a portion of which will be billed to partners in future periods as the rig is utilized.

(3) Investment in equity method investees represents funding of our investment in CONE which owns and operates the natural gas gathering infrastructure associated with our Marcellus Shale joint venture.

Total expenditures increased in 2014 as compared with 2013 due to accelerated activity in the DJ Basin and Marcellus Shale.

Financing Activities

Long-Term Debt Our principal source of liquidity is our Credit Facility that matures October 3, 2018. At March 31, 2014, we had $450 million outstanding under the Credit Facility, leaving almost $3.6 billion available for use. We expect to use the Credit Facility to fund our capital investment program, and may periodically borrow amounts for working capital purposes. See Item 1 Financial Statements – Note 6. Debt.

Our outstanding fixed-rate debt (excluding capital lease and other obligations) totaled approximately $4.5 billion at March 31, 2014. The weighted average interest rate on fixed-rate debt was 4.88%, with maturities ranging from April 2014 to August 2097. On April 15, 2014, we repaid $200 million of matured fixed rate debt.

Dividends We paid total cash dividends of 14 cents per share of our common stock during the first three months of 2014 and 12.5 cents per share during the first three months of 2013 (as adjusted for the 2-for-1 stock split during the second quarter of 2013).

On April 21, 2014, the Board of Directors increased the quarterly cash dividend to 18 cents per common share, which will be paid May 19, 2014 to shareholders of record on May 5, 2014. 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 from the exercise of stock options of $10 million during the first three months of 2014 and $22 million during the first three months of 2013.

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 247,674 shares with a value of $15 million during the first three months of 2014 and 245,660 shares with a value of $14 million during the first three months of 2013.

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 volatility 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, 2014, we had entered into variable to fixed price commodity swaps and three-way collars related to crude oil and natural gas sales. Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net liability position with a fair value of $100 million. Based on the March 31, 2014 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative liability by approximately $38 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative liability by approximately $10 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our Credit Facility and the amount of interest we earn on our short-term investments.

At March 31, 2014, we had approximately $4.9 billion (excluding capital lease and other obligations) of long-term debt outstanding. Of this amount, $4.5 billion was fixed-rate debt with a weighted average interest rate of 4.88%. 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, $450 million at March 31, 2014, was variable-rate debt. 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, 2014 balance of our variable-rate debt would result in a change in annual interest expense of approximately $1 million.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of March 31, 2014, our cash and cash equivalents totaled approximately $1.4 billion, approximately 52% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of March 31, 2014 would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as taxes payable in foreign tax jurisdictions, are settled in the foreign local currency. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities.

Net transaction gains and losses were de minimis for the first quarters of both 2014 and 2013.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

Disclosure Regarding Forward-Looking Statements

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

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

- our ability to make and integrate acquisitions;
- the impact of governmental fiscal terms and/or regulation, such as those involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

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Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2013, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2013 is available on our website at www.nobleenergyinc.com.

Item 4. Controls and Procedures

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

Part II. Other Information

Item 1. Legal Proceedings

West Virginia Matter In March 2013, we received seven Notices of Violation (NOV) and two Administrative Orders (Orders) from the West Virginia Department of Environmental Protection Office of Oil and Gas (OOG) regarding the unintentional discharge of a mixture of freshwater and produced water that occurred on or about the evening of February 22, 2013 from one of our permitted water storage facilities in Marshall County, West Virginia. At this time, the OOG has not established a proposed penalty for these NOVs or Orders. Given the uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

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, 2013.

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

The following table sets forth, for the periods indicated, our share repurchase activity:

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)
1/1/2014 - 1/31/2014	—	$—	—	—
2/1/2014 - 2/28/2014	247,209	62.37	—	—
3/1/2014 - 3/31/2014	465	67.85	—	—
Total	247,674	$62.38	—	—

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

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

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

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Signatures

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

NOBLE ENERGY, INC.
(Registrant)

Date April 24, 2014

/s/ Kenneth M. Fisher
Kenneth M. Fisher
Executive Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Incorporation of the Registrant (as amended through April 23, 2013), filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 and incorporated herein by reference.
3.2	By-Laws of Noble Energy, Inc. (as amended through April 23, 2013), filed as Exhibit 3.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 and incorporated herein by reference.
10.1	Amendment to Retention and Confidentiality Agreement between Noble Energy, Inc. and Ted D. Brown, Senior Vice President, dated February 24, 2014, filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 19, 2014) filed February 24, 2014 and incorporated herein by reference.
12.1	Calculation of ratio of earnings to fixed charges, filed herewith.
31.1	Certification of the Company’s Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	Certification of the Company’s Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	Certification of the Company’s Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	Certification of the Company’s Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document