NOBLE ENERGY INC
Form 10-Q
October 28, 2014
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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 September 30, 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 September 30, 2014, there were 361,856,652 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues				
Oil, Gas and NGL Sales	$1,228	$1,341	$3,893	$3,537
Income from Equity Method Investees	41	53	138	150
Total	1,269	1,394	4,031	3,687
Costs and Expenses				
Production Expense	217	221	697	619
Exploration Expense	217	60	350	211
Depreciation, Depletion and Amortization	460	412	1,297	1,146
General and Administrative	132	109	399	324
Gain on Divestitures	(30)	—	(72)	(12)
Asset Impairments	33	63	164	63
Other Operating Expense, Net	10	6	33	27
Total	1,039	871	2,868	2,378
Operating Income	230	523	1,163	1,309
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	(385)	157	(74)	69
Interest, Net of Amount Capitalized	52	46	151	104
Other Non-Operating (Income) Expense, Net	(13)	9	1	21
Total	(346)	212	78	194
Income from Continuing Operations Before Income Taxes	576	311	1,085	1,115
Income Tax Provision	157	116	274	330
Income from Continuing Operations	419	195	811	785
Discontinued Operations, Net of Tax	—	10	—	58
Net Income	$419	$205	$811	$843
Earnings Per Share, Basic				
Income from Continuing Operations	$1.16	$0.54	$2.25	$2.19
Discontinued Operations, Net of Tax	—	0.03	—	0.16
Net Income	$1.16	$0.57	$2.25	$2.35
Earnings Per Share, Diluted				
Income from Continuing Operations	$1.12	$0.53	$2.21	$2.17
Discontinued Operations, Net of Tax	—	0.03	—	0.16
Net Income	$1.12	$0.56	$2.21	$2.33
Weighted Average Number of Shares Outstanding				
Basic	362	359	361	359
Diluted	367	363	367	363

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$419	$205	$811	$843
Other Items of Comprehensive Income				
Net Change in Pension and Other	6	4	16	15
Less Tax Benefit	(2)	(1)	(6)	(5)
Other Comprehensive Income	4	3	10	10
Comprehensive Income	$423	$208	$821	$853

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

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

	September 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,169	$1,117
Accounts Receivable, Net	740	947
Other Current Assets	361	547
Total Current Assets	2,270	2,611
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	24,465	22,243
Property, Plant and Equipment, Other	618	517
Total Property, Plant and Equipment, Gross	25,083	22,760
Accumulated Depreciation, Depletion and Amortization	(7,325)	(7,035)
Total Property, Plant and Equipment, Net	17,758	15,725
Goodwill	620	627
Other Noncurrent Assets	538	679
Total Assets	$21,186	$19,642
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,425	$1,354
Other Current Liabilities	807	988
Total Current Liabilities	2,232	2,342
Long-Term Debt	5,498	4,566
Deferred Income Taxes, Noncurrent	2,464	2,441
Other Noncurrent Liabilities	1,054	1,109
Total Liabilities	11,248	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; 402 Million and 400 Million Shares Issued, respectively	4	4
Additional Paid in Capital	3,593	3,463
Accumulated Other Comprehensive Loss	(107)	(117)
Treasury Stock, at Cost; 38 Million Shares	(674)	(659)
Retained Earnings	7,122	6,493
Total Shareholders’ Equity	9,938	9,184
Total Liabilities and Shareholders’ Equity	$21,186	$19,642

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

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

	Nine Months Ended September 30,	
	2014	2013
Cash Flows From Operating Activities		
Net Income	$811	$843
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,297	1,148
Asset Impairments	164	63
Dry Hole Cost	163	22
Deferred Income Taxes	61	168
Income from Equity Method Investees, Net of Dividends	53	(12)
(Gain) Loss on Commodity Derivative Instruments	(74)	69
Net Cash Received (Paid) in Settlement of Commodity Derivative Instruments	(95)	(2)
Gain on Divestitures	(72)	(67)
Stock Based Compensation	67	59
Other Adjustments for Noncash Items Included in Income	42	63
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	166	(260)
Increase in Accounts Payable	103	63
Increase (Decrease) in Current Income Taxes Payable	21	(48)
Increase (Decrease) in Other Current Assets and Liabilities, Net	16	(7)
Other Noncurrent Operating Assets and Liabilities, Net	(20)	51
Net Cash Provided by Operating Activities	2,703	2,153
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(3,585)	(3,021)
Additions to Equity Method Investments	(58)	(30)
Distribution from Equity Method Investee	156	—
Proceeds from Divestitures	312	119
Other	—	(5)
Net Cash Used in Investing Activities	(3,175)	(2,937)
Cash Flows From Financing Activities		
Exercise of Stock Options	45	39
Excess Tax Benefits from Stock-Based Awards	18	15
Dividends Paid, Common Stock	(182)	(146)
Purchase of Treasury Stock	(15)	(14)
Proceeds from Credit Facilities	900	800
Repayment of CONSOL Installment Loan	—	(328)
Repayment of Senior Notes	(200)	—
Repayment of Capital Lease Obligation	(42)	(31)
Net Cash Provided by Financing Activities	524	335
Increase (Decrease) in Cash and Cash Equivalents	52	(449)
Cash and Cash Equivalents at Beginning of Period	1,117	1,387
Cash and Cash Equivalents at End of Period	$1,169	$938

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	—		—	—	811	811
Stock-based Compensation	—	67	—	—	—	67
Exercise of Stock Options	—	45	—	—	—	45
Tax Benefits Related to Exercise of Stock Options	—	18	—	—	—	18
Dividends (50 cents per share)	—	—	—	—	(182)	(182)
Changes in Treasury Stock, Net	—	—	—	(15)	—	(15)
Net Change in Pension and Other	—	—	10	—	—	10
September 30, 2014	$4	$3,593	$(107)	$(674)	$7,122	$9,938
December 31, 2012	$4	$3,302	$(113)	$(648)	$5,713	$8,258
Net Income	—	—	—	—	843	843
Stock-based Compensation	—	59	—	—	—	59
Exercise of Stock Options	—	39	—	—	—	39
Tax Benefits Related to Exercise of Stock Options	—	15	—	—	—	15
Dividends (41 cents per share)	—	—	—	—	(146)	(146)
Changes in Treasury Stock, Net	—	—	—	(14)	—	(14)
Net Change in Pension and Other	—	—	10	—	—	10
September 30, 2013	$4	$3,415	$(103)	$(662)	$6,410	$9,064

(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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Noble Energy, Inc.
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 September 30, 2014 and December 31, 2013 and for the three and nine months ended September 30, 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. Certain prior-period amounts have been reclassified to conform to the current-period presentation. Operating results for the three and nine months ended September 30, 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.
Equity Investees On September 24, 2014, our equity method investee, CONE Gathering LLC (CONE Gathering), contributed substantially all of its assets to a newly-formed master limited partnership, CONE Midstream Partners LP (CONE Midstream), concurrently with an initial public offering of limited partner units. CONE Gathering subsequently made a cash distribution of $204 million to us, which is reflected within cash flows from operating activities ($48 million) and cash flows from investing activities ($156 million) within our consolidated statement of cash flows. As a result of the transaction, we own a 32.1% interest in CONE Midstream, which we account for using the equity method of accounting.
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 the first, second, and third quarters 2014. In addition, we recorded impairments for the North Sea assets in both the first and second quarters of 2014. See Note 4. Asset Impairments.
North Sea revenues and operating expenses for the nine months ended September 30, 2014, except for the impairments recorded in the first and second quarters 2014, 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. Early adoption is permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. We elected to early adopt ASU 2014-08 on a prospective basis, and the adoption did not have a material impact on our consolidated financial statements.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, Revenue from Contracts with Customers, and supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, ASU 2014-09 supersedes the cost guidance in Subtopic 605-35, Revenue Recognition - Construction-Type and Production-Type Contracts, and creates new Subtopic 340-40, Other Assets and Deferred Costs - Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and early application is not permitted. We are currently evaluating the provisions of ASU 2014-09 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2014	2013	2014	2013
Production Expense				
Lease Operating Expense	$133	$137	$432	$393
Production and Ad Valorem Taxes	44	51	146	137
Transportation and Gathering Expense	40	33	119	89
Total	$217	$221	$697	$619
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (Income) Expense [1]	$(12)	$10	$—	$24
Other (Income) Expense, Net	(1)	(1)	1	(3)
Total	$(13)	$9	$1	$21

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

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	September 30, 2014	December 31, 2013
Accounts Receivable, Net		
Commodity Sales	$345	$495
Joint Interest Billings	310	382
Other	101	81
Allowance for Doubtful Accounts	(16)	(11)
Total	$740	$947
Other Current Assets		
Inventories, Materials and Supplies	$95	$96
Inventories, Crude Oil	28	25
Commodity Derivative Assets	79	1
Deferred Income Taxes, Net	5	62
Assets Held for Sale	98	292
Prepaid Expenses and Other Current Assets	56	71
Total	$361	$547
Other Noncurrent Assets		
Equity Method Investments	$290	$437
Mutual Fund Investments	121	114
Commodity Derivative Assets	32	16
Other Assets	95	112
Total	$538	$679
Other Current Liabilities		
Production and Ad Valorem Taxes	$110	$103
Commodity Derivative Liabilities	—	65
Income Taxes Payable	183	156
Asset Retirement Obligations	155	39
Interest Payable	56	63
Current Portion of Long Term Debt	—	200
Current Portion of Capital Lease	67	58
Liabilities Associated with Assets Held for Sale	12	111
Other	224	193
Total	$807	$988
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$264	$253
Asset Retirement Obligations	543	547
Accrued Benefit Costs	108	155
Commodity Derivative Liabilities	—	10
Other	139	144
Total	$1,054	$1,109

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Note 3. Divestitures
Onshore US Properties During the first nine 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 September 30, 2014	Nine Months Ended September 30, 2014
Sales Proceeds	$16	$126
Less		
Net Book Value of Assets Sold	—	(118)
Goodwill Allocated to Assets Sold	(1)	(7)
Asset Retirement Obligations Associated with Assets Sold	14	34
Other Closing Adjustments	1	2
Gain on Divestitures	$30	$37

On October 23, 2014, we closed the sale of our non-core onshore US properties in the Piceance Basin of western Colorado, with net proceeds of $9 million. These properties were reclassified as held for sale at September 30, 2014, and written down to expected proceeds less costs to sell which resulted in an impairment charge of $31 million. See Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures.
In October 2014, we signed a purchase and sale agreement related to certain of our properties located on the western side of the DJ Basin, outside of our core DJ Basin operating area. The sale is expected to close in late 2014, with net proceeds of approximately $145 million.
China On June 30, 2014, we closed the sale of our China assets. The information regarding the China assets sold is as follows:

(millions)	Nine Months Ended September 30, 2014
Sales Proceeds	$186
Less	
Net Book Value of Assets Sold	(149)
Other Closing Adjustments	(2)
Gain on Divestiture	35

Offshore Israel Properties Assets held for sale as of September 30, 2014, include two natural gas discoveries, Tanin and Karish, 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.
North Sea Properties During the first nine months of 2013, we sold non-operated working interests in properties located in the North Sea. The sales resulted in a $55 million gain based on net sales proceeds of $54 million. See Note 2. Basis of Presentation - Discontinued Operations.
Summarized results of discontinued operations are as follows:

(millions)	Nine Months Ended September 30, 2013
Oil and Gas Sales	$32
Income Before Income Taxes	10
Income Tax Expense	7
Operating Loss, Net of Tax	3
Gain on Sale, Net of Tax	55

Discontinued Operations, Net of Tax	$58

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2014	2013	2014	2013
Deepwater Gulf of Mexico (US Properties)	$2	$16	$25	$16
Piceance Basin (US Properties)	31	—	31	—
Mari-B (Offshore Israel)	—	47	14	47
McCulloch and Other North Sea Properties	—	—	94	—
Total	$33	$63	$164	$63

US and Offshore Israel During the third quarter of 2014, we reclassified our non-core onshore US properties in the Piceance Basin as assets held for sale. The assets were written down to expected proceeds less costs to sell.
During the first nine months of 2014, the asset carrying values of certain oil and natural gas assets in the deepwater Gulf of Mexico and offshore Israel increased when we recorded associated increases in asset retirement obligations. We determined that the recorded asset carrying values of some of these assets were not recoverable from future cash flows and recorded impairment expense. US properties included the currently-producing Raton natural gas well, as well as the Conquest and Gemini fields, which are being abandoned.
North Sea In March 2014, the operator of one of our remaining North Sea 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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Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 decreases 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 September 30, 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 September 30, 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	27,000	88.80	—	—	—
2015	Swaps	Dated Brent	8,000	100.31	—	—	—
2015	Three-Way Collars	NYMEX WTI	20,000	—	70.50	87.55	94.41
2015	Three-Way Collars	Dated Brent	13,000	—	76.92	96.00	108.49
2016	Swaps	NYMEX WTI	6,000	87.95	—	—	—
2016	Swaps	Dated Brent	9,000	97.96	—	—	—
2016	Three-Way Collars	NYMEX WTI	3,000	—	72.00	85.00	94.82
2016	Three-Way Collars	Dated Brent	6,000	—	80.00	95.00	105.87

(1) West Texas Intermediate

As of September 30, 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 September 30, 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	140,000	4.30	—	—	—
2015	Three-Way Collars	NYMEX HH	150,000	—	3.58	4.25	5.04

(1) Henry Hub

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Fair Value Amounts and (Gain) 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			
	September 30, 2014		December 31, 2013		September 30, 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	$79	Current Assets	$1	Current Liabilities	$—	Current Liabilities	$65
	Noncurrent Assets	32	Noncurrent Assets	16	Noncurrent Liabilities	—	Noncurrent Liabilities	10
Total		$111		$17		$—		$75

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2014	2013	2014	2013
(Gain) Loss on Commodity Derivative Instruments				
Crude Oil	$(360)	$167	$(68)	$99
Natural Gas	(25)	(10)	(6)	(30)
Total (Gain) Loss on Commodity Derivative Instruments	(385)	157	(74)	69
Cash (Received) Paid in Settlement of Commodity Derivative Instruments				
Crude Oil	14	24	87	39
Natural Gas	(2)	(14)	8	(37)
Total Cash (Received) Paid in Settlement of Commodity Derivative Instruments	12	10	95	2
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments				
Crude Oil	(374)	143	(155)	60
Natural Gas	(23)	4	(14)	7
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	$(397)	$147	$(169)	$67

AOCL Accumulated other comprehensive loss (AOCL) at September 30, 2014 included deferred losses of $23 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 term of our senior notes due 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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Note 6. Debt
Debt consists of the following:

(millions, except percentages)	September 30, 2014 Debt	Interest Rate		December 31, 2013 Debt	Interest Rate	
Credit Facility, due October 3, 2018	$900	1.43	%	$—	—	%
Capital Lease and Other Obligations	399	—		359	—	
5¼% Senior Notes, due April 15, 2014 [1]	—	—		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	5,583			4,843		
Unamortized Discount	(18)			(19)		
Total Debt, Net of Discount	5,565			4,824		
Less Amounts Due Within One Year						
5¼% Senior Notes, due April 15, 2014, net of discount [1]	—			(200)		
Capital Lease Obligations	(67)			(58)		
Long-Term Debt Due After One Year	$5,498			$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.
Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [2]	Significant Unobservable Inputs (Level 3) [3]	Adjustment [4]	Fair Value Measurement
(millions)					
September 30, 2014					
Financial Assets					
Mutual Fund Investments	$121	$—	$—	$—	$121
Commodity Derivative Instruments	—	117	—	(6)	111
Financial Liabilities					
Commodity Derivative Instruments	—	(6)	—	6	—
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 September 30, 2014					

Impaired Oil and Gas Properties	$—	$—	$9	$42	$33
Three Months Ended September 30, 2013					
Impaired Oil and Gas Properties	—	—	75	138	63
Nine Months Ended September 30, 2014					
Impaired Oil and Gas Properties	$—	$—	$23	$187	$164
Nine Months Ended September 30, 2013					
Impaired Oil and Gas Properties	—	—	75	138	63

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

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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 and natural gas production prior to abandonment date, commodity prices based on NYMEX WTI, NYMEX Henry Hub, and Brent future price curves as of the date of the estimate, estimated operating and abandonment costs, and a risk-adjusted discount rate of 10%. First and second quarter 2014 impairments were due to increases in asset carrying values associated with increases in asset retirement obligations (ARO). ARO increases were due to higher cost and change in timing of abandonment activities. Third quarter 2014 impairments related primarily to our non-core onshore properties in the Piceance Basin, which were reclassified as assets held for sale. The assets were written down to expected proceeds less costs to sell. 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 September 30, 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 measurement on the fair value hierarchy. See Note 6. Debt.

Fair value information regarding our debt is as follows:

	September 30, 2014		December 31, 2013	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total Debt, Net of Unamortized Discount [1]	$5,166	$5,805	$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)	Nine Months Ended September 30, 2014
Capitalized Exploratory Well Costs, Beginning of Period	$1,301
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	274
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale	(186)
Capitalized Exploratory Well Costs Charged to Expense [1]	(85)
Capitalized Exploratory Well Costs, End of Period	$1,304

[1] Capitalized exploratory wells costs charged to expense primarily represent the Scotia exploratory well, offshore Falkland Islands, which was determined to be non-commercial.

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)	September 30, 2014	December 31, 2013
Exploratory Well Costs Capitalized for a Period of One Year or Less	$307	$568
	997	733

Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling		
Balance at End of Period	$1,304	$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

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The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of September 30, 2014:

		Suspended Since			
(millions)	Total	2012 - 2013	2010 - 2011	2009 & Prior	Progress
Country/Project:					
Deepwater Gulf of Mexico					
Troubadour	$44	$44	$—	$—	Evaluating development scenarios for this 2013 natural gas discovery
Offshore Equatorial Guinea					
Diega (including Carmen)	161	56	52	53	Evaluating regional development scenarios for this 2008 crude oil discovery
Carla	150	138	12	—	Evaluating regional development scenarios for this 2011 crude oil discovery
Felicita	38	3	6	29	Evaluating regional development plans for this 2008 condensate and natural gas discovery
Yolanda	19	2	3	14	Evaluating regional development plans for this 2007 condensate and natural gas discovery
Offshore Cameroon					
YoYo	47	4	9	34	Working with the government to assess commercialization of this 2007 condensate and natural gas discovery
Offshore Israel					
Leviathan	181	71	110	—	Submitted a development plan to the Israeli government; finalizing front-end engineering and design (FEED) work; continuing marketing activities with potential natural gas customers
Leviathan-1 Deep	77	50	27	—	Well did not reach the target interval; developing future drilling plans to test this deep oil concept
Dalit	26	4	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	25	3	22	—	Reviewing regional development scenarios for this 2011 natural gas discovery
Offshore Cyprus					
Cyprus	188	131	57	—	Discussing monetization options with the Cyprus government for this 2011 natural gas discovery
Other					
Projects less than $20 million	41	31	4	6	Continuing to drill and evaluate wells
Total	$997	$537	$304	$156	

Note 9. Asset Retirement Obligations

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:

	Nine Months Ended September 30,	
(millions)	2014	2013
Asset Retirement Obligations, Beginning Balance	$586	$402
Liabilities Incurred	38	4
Liabilities Settled	(77)	(15)
Revision of Estimate	123	5
Accretion Expense [1]	28	21
Asset Retirement Obligations, Ending Balance	$698	$417

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

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For the nine months ended September 30, 2014
Liabilities incurred were due to new wells and facilities and included $13 million for onshore US, $16 million for deepwater Gulf of Mexico, and $9 million for Eastern Mediterranean.
Liabilities settled primarily related to onshore US property abandonments and non-core, onshore US assets sold. At December 31, 2013, our non-operated North Sea fields were classified as held for sale, which included the related ARO for these fields. During 2014, we reclassified the remaining, unsold North Sea properties as held and used. The North Sea field ARO of $24 million is recorded within liabilities settled.
Revisions were primarily due to an increase of $67 million related to a non-operated North Sea field due to an increase in costs and a change in timing recorded during the first quarter of 2014. See Note 4. Asset Impairments.
Additional revisions were due to changes in cost and timing estimates and primarily included $21 million for DJ Basin, $16 million for Equatorial Guinea, $9 million for Eastern Mediterranean, and $9 million for deepwater Gulf of Mexico.
For the nine months ended September 30, 2013
Liabilities incurred were due to new wells and facilities for onshore development. Liabilities settled in 2013 relate primarily to non-core onshore US properties that were sold. See Note 3. Divestitures.

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 September 30,		Nine Months Ended September 30,	
(millions, except per share amounts)	2014	2013	2014	2013
Income from Continuing Operations	$419	$195	$811	$785
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	(8)	—	—	—
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$411	$195	$811	$785
Weighted Average Number of Shares Outstanding, Basic	362	359	361	359
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	5	4	6	4
Weighted Average Number of Shares Outstanding, Diluted	367	363	367	363
Earnings from Continuing Operations Per Share, Basic	$1.16	$0.54	$2.25	$2.19
Earnings from Continuing Operations Per Share, Diluted	1.12	0.53	2.21	2.17
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	2	4	3	5

(1) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while our common shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculations for the three and nine months ended September 30, 2014 exclude deferred compensation (gains) losses, net of tax. The deferred compensation loss, net of tax, excluded for the calculation of diluted earnings per share for the nine months ended September 30, 2014 was de minimis.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2014	2013	2014	2013
Current	$120	$53	$213	$161
Deferred	37	63	61	169
Total Income Tax Provision	$157	$116	$274	$330
Effective Tax Rate	27.2 %	37.2 %	25.3 %	29.6 %

Our effective tax rate (ETR) for the three and nine months ended September 30, 2014 decreased as compared with the three and nine months ended September 30, 2013 primarily due to our ability to benefit from previously unrecognized foreign tax credits, increased earnings in our foreign jurisdictions with rates that vary from the US statutory rate, and a decrease in our Israeli oil profits tax. Additionally, in July 2013, the Israeli government increased the corporate income tax rate from 25% to 26.5%. The change increased the deferred tax expense for 2013, which resulted in a higher rate for the three months ended September 30, 2013 as compared to the same period of 2014.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2011, Equatorial Guinea – 2009 and Israel – 2009.

See Note 3. Divestitures for income taxes associated with discontinued operations.

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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, Sierra Leone, and Gabon); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, China (through June 30, 2014), Falkland Islands, Nicaragua and new ventures. The North Sea geographical segment is included in continuing operations in 2014 and discontinued operations in 2013. Income (loss) from continuing operations before income taxes for the United States and West Africa includes gains and losses on commodity derivative instruments.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended September 30, 2014					
Revenues from Third Parties	$1,228	$819	$269	$138	$2
Income from Equity Method Investees	41	—	41	—	—
Total Revenues	1,269	819	310	138	2
DD&A	460	351	70	17	22
Gain on Divestitures	(30)	(30)	—	—	—
Asset Impairments	33	33	—	—	—
Income (Loss) from Continuing Operations Before Income Taxes	576	457	321	90	(292)
Three Months Ended September 30, 2013					
Revenues from Third Parties	$1,341	$810	$372	$122	$37
Income from Equity Method Investees	53	—	53	—	—
Total Revenues	1,394	810	425	122	37
DD&A	412	295	72	26	19
Gain on Divestitures	—	—	—	—	—
Asset Impairments	63	16	—	47	—
Income (Loss) from Continuing Operations Before Income Taxes	311	183	223	34	(129)
Nine Months Ended September 30, 2014					
Revenues from Third Parties	$3,893	$2,503	$931	$363	$96
Income from Equity Method Investees	138	—	138	—	—
Total Revenues	4,031	2,503	1,069	363	96
DD&A	1,297	970	218	46	63
Gain on Divestitures	(72)	(36)	—	—	(36)
Asset Impairments	164	56	—	14	94
Income (Loss) from Continuing Operations Before Income Taxes	1,085	838	786	211	(750)
Nine Months Ended September 30, 2013					
Revenues from Third Parties	$3,537	$2,209	$935	$274	$119
Income from Equity Method Investees	150	—	150	—	—
Total Revenues	3,687	2,209	1,085	274	119
DD&A	1,146	819	189	81	57
Gain on Divestitures	(12)	(12)	—	—	—
Asset Impairments	63	16	—	47	—
	1,115	746	722	93	(446)

Income (Loss) from Continuing Operations Before Income Taxes					
September 30, 2014					
Total Assets	$21,186	$15,069	$2,930	$2,855	$332
December 31, 2013					
Total Assets	19,598	13,094	3,199	2,753	552

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 equal or exceed $4.00 per MMBtu for three consecutive months. Due to low natural gas prices, the CONSOL Carried Cost Obligation was suspended from the end of 2011 until February 28, 2014. 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 September 30, 2014 NYMEX Henry Hub natural gas price curve and current development plans, we forecast we will incur approximately $185 million under the CONSOL Carried Cost Obligation for the year ended December 31, 2014.

Marcellus Shale Firm Transportation Agreements During 2014, we signed Precedent Agreements for Firm Transportation (the Agreements) to flow 445,000 MMBtu per day of our Marcellus Shale natural gas production to various 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 2017 and 2018. Our financial commitment totals approximately $1.2 billion, undiscounted, over a 15-year period. Final 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 explorer and producer of crude oil, natural gas and natural gas liquids. 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 exploration activities in domestic and international locations such as Northeast Nevada, Gabon, the Falkland Islands, Cameroon, and Cyprus.

Our financial results for third quarter 2014 included:

- net income of $419 million, as compared with $205 million for third quarter 2013;
- gain on commodity derivative instruments of $385 million (including $397 million non-cash portion of gain) as compared with a loss on commodity derivative instruments of $157 million (including $147 million non-cash portion of loss) for third quarter 2013;
- dry hole expense of $161 million, as compared with third quarter 2013, which was de minimis;
- asset impairment charges of $33 million, as compared with $63 million for third quarter 2013;
- diluted earnings per share of $1.12, as compared with $0.56 for third quarter 2013;
- cash flow provided by operating activities of $946 million, as compared with $909 million for third quarter 2013;
- ending cash balance of $1.2 billion, as compared with $1.1 billion at December 31, 2013;
- capital spending, on a cash basis, of $1.1 billion, as compared with $1.1 billion for the third quarter 2013;
- net increase in our unsecured revolving credit facility (Credit Facility) balance of $300 million;
- cash distributions of $204 million received from CONE Gathering LLC (CONE Gathering);
- total liquidity of $4.3 billion at September 30, 2014, as compared with $5.1 billion at December 31, 2013; and
- ratio of debt-to-book capital of 36% at September 30, 2014, as compared with 35% at December 31, 2013.

Our operating results for third quarter 2014 included:

- formed a master limited partnership with CONSOL Energy Inc. (CONSOL) for our jointly owned midstream assets in the Marcellus Shale and completed the initial public offering;
- announced successful final well results at the Katmai exploratory well and at the Dantzler-2 appraisal well located in the deepwater Gulf of Mexico;
- signed a regional export Letter of Intent (LOI) for natural gas sales from Leviathan to National Electric Power Company of Jordan; and
- entered into a new position offshore West Africa in Gabon.

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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 September 30, 2014 (See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs), and expect to continue an active exploratory drilling program in the future.

A portion of our 2014 capital investment program is dedicated to exploration and associated appraisal activities, including seismic and 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 recorded as dry hole 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 currently analyzing results from our first two exploratory vertical wells and conducting a production test. In third quarter 2014, we commenced drilling a third exploratory well and plan to drill additional exploratory wells in 2015.

Deepwater Gulf of Mexico   In third quarter 2014, we announced successful final well results at the Katmai exploratory well (Green Canyon Block 40, 50% operated working interest) in the deepwater Gulf of Mexico. Katmai was drilled to a total depth of 27,900 feet in 2,100 feet of water. Wireline logging data indicated a total of 154 net feet of crude oil pay discovered in multiple reservoirs, including 117 net feet in Middle Miocene and 37 net feet in Lower Miocene reservoirs. Additional exploration and appraisal drilling will be required to test the remaining resource potential.

We participated with a 50% non-operated working interest in the Bright prospect, which was drilled on Atwater Valley Block 362 to a total depth of 13,500 feet during the third quarter 2014. The exploratory well reached the targeted Upper and Middle Miocene objectives and was subsequently plugged and abandoned as we did not encounter hydrocarbons. As a result, we recorded $79 million dry hole cost in the third quarter of 2014.

In the fourth quarter 2014, we plan to drill the Madison prospect (Mississippi Canyon 479), where we have a 60% working interest.

Offshore West Africa We are currently acquiring 3D seismic data across Blocks O and I, offshore Equatorial Guinea, and reprocessing 3D seismic data over our YoYo mining concession, offshore Cameroon.

In August 2014, we expanded our exploration portfolio by signing a Production Sharing Contract (PSC) with the Government of Gabon covering Block F15. Block F15 is located in the Gabon Coastal Basin and covers over 670,000 gross acres. The PSC includes a 4-year seismic commitment and an option for exploration drilling. We have a 60% operated working interest.

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 in Israel and Cyprus.

Offshore Falkland Islands We anticipate drilling operations to begin in mid-2015 at Humpback, our operated prospect located in the Fitzroy sub-basin of the Southern Area License. We are currently finalizing locations for a second exploratory well, planned for later in 2015 following results at Humpback. We operate our Southern Area licenses with a 35% working interest.

Based on the results of seismic interpretation conducted on the Scotia exploratory well which was drilled in 2012, we have concluded that the Scotia prospect is not economically viable. As a result, we recorded $73 million dry hole expense during third quarter 2014.

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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 an extensive level of horizontal drilling activity with continued growth from new wells brought online and expanded natural gas and crude oil infrastructure. We have accelerated our extended reach lateral well program to approximately 30% of our wells to be drilled in 2014. During the quarter, we spud 75 horizontal wells, of which 22 were extended reach lateral wells, and 68 wells initiated production. Our 2014 drilling program includes over 90 extended reach lateral wells. Currently, nine drilling rigs are active across the basin.

Marcellus Shale (Onshore US) We continue to delineate the wet gas acreage, while our partner, CONSOL, continues to develop the dry gas acreage. During the quarter, we and our partner drilled 50 wells, and 37 wells initiated production. The joint venture is currently operating eight 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.

On September 24, 2014, our jointly-owned equity method investee, CONE Gathering, contributed substantially all of its assets to a newly-formed master limited partnership, CONE Midstream Partners LP (CONE Midstream). CONE Gathering subsequently made a cash distribution of $204 million to each of us and CONSOL. In addition, we and CONSOL each own a 32.1% interest in CONE Midstream. CONE Midstream will own, operate, and develop our jointly-owned natural gas midstream assets in the Marcellus Shale.

Gunflint (Deepwater Gulf of Mexico) Development is on track for the Gunflint crude oil discovery, utilizing a two-well subsea tieback to the Gulfstar 1 spar platform. Topsides equipment fabrication is underway for planned 2015 installation, and we are targeting first production for mid-2016.

Big Bend and Dantzler (Deepwater Gulf of Mexico) A co-development project is underway for the Big Bend (54% operated working interest) and Dantzler (45% operated working interest) crude oil discoveries, located in the Rio Grande area of the deepwater Gulf of Mexico.

During third quarter 2014, we announced final well results at the Dantzler-2 appraisal well, located in Mississippi Canyon 782, which encountered 122 net feet of crude oil pay in two high-quality Miocene reservoirs. The well was drilled to a total depth of 18,210 feet in 6,600 feet of water.

We recently signed a production handling agreement for tie back to the Thunder Hawk semi-submersible production facility. First production for Big Bend is targeted for fourth quarter 2015, and first production for Dantzler is targeted for first quarter 2016.

Tamar Expansion (Offshore Israel) The Tamar compression project is ongoing. De-bottlenecking of the Tamar facilities has increased current peak production deliverability at Tamar to more than 1.1 Bcf/d, gross. Additional progress was made at the Ashdod onshore terminal, which brings the project to approximately 80% complete. The expansion is targeted to increase deliverability at Tamar to 1.2 Bcf/d, gross, beginning in mid-2015.

We are continuing to work with the Israeli government to obtain regulatory approval of our development plan for the Tamar Southwest discovery, which is intended to utilize current Tamar infrastructure. Continuing delays in securing regulatory approvals have placed the project at risk of delay. We have petitioned the Israeli courts to expedite the needed approvals. Timely development of Tamar Southwest is important to maintain well capacity and reliability for our overall Tamar project.

In May 2014, we announced that we had entered into a non-binding LOI for the supply of natural gas from the Tamar field to existing natural gas liquefaction (LNG) facilities in Egypt.

Unsanctioned Development Projects (As of September 30, 2014)

Leviathan (Offshore Israel) We have made significant progress on the development of the Leviathan field, following approval of Israel's natural gas export policy, an agreement with Israel's Anti-trust Authority, and receipt of the Development and Production Leases for Leviathan.

We have submitted the Plan of Development for the initial phase of development of Leviathan to the Ministry of Energy and Water Resources. The initial phase of development is planned to include a 1.6 Bcf/d Floating, Production, Storage, and Offloading (FPSO) vessel, with initial sales targeted to begin in early 2018 at 75% of total FPSO capacity.

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We have also entered into two non-binding LOIs for the supply of natural gas from the Leviathan field. In June 2014, we announced an LOI to supply natural gas to existing LNG facilities in Egypt. In September 2014, we announced an LOI to supply natural gas to the National Electric Power Company of Jordan. We are working towards final gas purchase and sales agreements, which will be subject to, among other conditions, the receipt of regulatory approvals. We are engaged with the governments of the US, Israel, Jordan and Egypt.

Project financing discussions are underway, and we are targeting to sanction Phase 1 in 2015.

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

Cyprus Project (Offshore Cyprus) We are currently evaluating development scenarios in Cyprus. Our application for renewal of the production sharing contract for two additional years was approved in May 2014.

Diega and Carla (Offshore Equatorial Guinea) We are currently evaluating regional development scenarios for Diega and Carla and will incorporate the results of our 3D seismic data acquisition across Blocks O and I. A natural gas sales agreement has been executed by the Block O and I partners to sell dedicated natural gas from the Alen field to the proposed Integrated Petrochemical Complex in Equatorial Guinea.

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

We have continued our non-core asset divestiture program with the sale of our China assets as well as certain smaller onshore US property packages during the first nine months of 2014. In addition we closed the sale of our Piceance Basin properties in October 2014. Divestitures of non-core properties allow us to allocate capital and human 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 countries of former operations. 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.

Update on Israel's Natural Gas Economy

Israel Antitrust Authority During 2014, we and our partners 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 are progressing the other actions required to complete the sale. The assets are reported within assets held for sale in our consolidated balance sheet at September 30, 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 primary 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 draft 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 and have submitted comments and suggestions to the Ministry.

Update on Hydraulic Fracturing

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.

A measure to ban hydraulic fracturing was on the ballot in the City of Loveland in northern Colorado in June of 2014. The oil and gas industry worked with the community to defeat that initiative. Also during 2014, we actively worked to avoid statewide ballot initiatives that would unreasonably restrict or limit crude oil and natural gas development in Colorado. On August 4, 2014, an agreement was reached with supporters of the ballot initiatives to withdraw all ballot measures relating to oil and natural gas and to support the creation of a Task Force on State and Local Regulation of Oil and Gas Operations (Task Force). Colorado Governor Hickenlooper created the Task Force by executive order and named 21 members to it, for the purpose of recommending policies and legislation by February 27, 2015. A Noble

Energy representative is a member of the Task Force.
In Nevada, state regulators are in the process of promulgating rules to govern hydraulic fracturing and crude oil and natural gas development. We have actively participated in that process and do not believe it will have a material impact on our activities.

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In addition to the above, we will continue to monitor proposed and new legislation and regulations in all operating jurisdictions to assess the potential impact on our company. Concurrently, we are engaged in extensive public education and outreach efforts with the goal of engaging and educating the general public and communities about the energy, economic and environmental benefits of safe and responsible crude oil and natural gas development.

Update on West Africa Operations

An epidemic of the Ebola virus is ongoing in certain regions of West Africa and may adversely affect our business operations through travel or other restrictions which could have an impact on business continuity. We continue to monitor and prepare for potential escalation.

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 US Environmental Protection Agency'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 developments. On a BOE basis, total sales volumes were 3% higher for the third quarter of 2014 as compared with the third quarter of 2013, and our mix of sales volumes was 43% global liquids, 27% international natural gas, and 30% US natural gas. Increases in onshore US sales were offset by the impacts of the DJ Basin acreage exchange in fourth quarter 2013 and recent divestments. See Results of Operations – Revenues, below.

Commodity Price Changes

Average realized crude oil prices decreased 9% in the US and 8% in Equatorial Guinea for the third quarter of 2014 as compared with the third quarter of 2013. Average realized natural gas prices decreased 5% in the US and increased 10% in Israel for third quarter of 2014 as compared with the third quarter of 2013.

In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows, we have hedged approximately 65% of our expected global crude oil production and approximately 60% of our expected domestic natural gas production for the remainder of 2014.

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;
- impact of potential pipeline and processing facility capacity constraints in the DJ Basin and 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 and the Alba and Aseng fields offshore Equatorial Guinea; and
- potential weather-related volume curtailments such as severely cold weather in the DJ Basin and Marcellus Shale, which can shut-in or reduce production.

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.

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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 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, we are in the process of conducting exploration activities in several onshore US areas, such as the Permian Basin area of West Texas. If we conclude that the prospect is not economically viable, costs incurred would be recorded as dry hole expense. The Permian Basin properties had a net book value of approximately $60 million at September 30, 2014.

During third quarter 2014, we drilled the Bright exploratory well in the deepwater Gulf of Mexico, which did not encounter hydrocarbons. Also, based on the results of recent seismic interpretation conducted on the Scotia exploratory well drilled in 2012, offshore Falkland Islands, we have concluded that the Scotia prospect is not economically viable. As such, the costs that we incurred on both Bright and Scotia prospects have been recorded as 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 under regulations in effect prior to the Deepwater Gulf of Mexico Moratorium, expired on July 31, 2014. We have been working to mature this prospect by conducting various activities, including the licensing and processing of 3D seismic data and interpretation of geophysical information, which have resulted in the identification of a potential subsalt hydrocarbon-bearing formation below 25,000 feet. Our lease maturation activity of the sub-25,000 foot subsalt objective should satisfy the requirements needed to be granted an extension of the lease term for a period sufficient to complete the lease maturation and to commit to drilling a well to evaluate the prospect. Accordingly, we submitted an application to the Bureau of Safety and Environmental Enforcement (BSEE) on July 7, 2014 justifying and requesting a suspension of operations (SOO) for the lease and, at BSEE's request, submitted additional information in September 2014. An approved SOO will allow us to continue to process the subsalt image and to initiate efforts to establish a multi-company partnership to mature the prospect and design an appropriate well to drill and evaluate the prospect with a targeted spud date in 2017. We believe we have satisfied the requirements for the SOO and expect that a favorable decision from BSEE will be forthcoming. However, there is no certainty a lease extension will be formally approved by BSEE. The lease had a net book value of approximately $41 million at September 30, 2014. If BSEE denies our application for the lease SOO and extension, we will write off the book value of the lease to exploration expense.

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 was shut-in due to mechanical issues. The well was brought back online at the end of third quarter 2014 and, as part of our

remediation plan, was granted a 180 day SOO to conduct remediation activities. No impairment is currently indicated; however, we will monitor production and reserves and continue to assess the field for possible impairment. South Raton had a net book value of $123 million at September 30, 2014.
In addition, well decommissioning programs, especially in deepwater or remote locations, are often complex and 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 higher demand. Therefore, our ARO estimates may change, sometimes significantly, and could result in asset impairment.

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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. For example, in September 2014, we signed a purchase and sale agreement related to our non-core onshore US properties in the Piceance Basin of western Colorado. These properties were reclassified as held for sale at September 30, 2014 and recorded at anticipated sales proceeds less costs to sell, which resulted in an impairment charge of $31 million. See Note 3. Divestitures, Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures In addition, certain assets offshore Israel were classified as held for sale at September 30, 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 nine 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 2014. See also Discontinued Operations, below.

Revenues

Revenues were as follows:

(millions)	2014	2013	Increase/(Decrease) from Prior Year	
Three Months Ended September 30,				
Oil, Gas and NGL Sales	$1,228	$1,341	(8	)%
Income from Equity Method Investees	41	53	(23	)%
Total	$1,269	$1,394	(9	)%
Nine Months Ended September 30,				
Oil, Gas and NGL Sales	$3,893	$3,537	10	%
Income from Equity Method Investees	138	150	(8	)%
Total	$4,031	$3,687	9	%

Changes in revenues are discussed below.

Oil, Gas and NGL Sales

We generally sell crude oil, natural gas, and NGLs under two types of agreements, which are common in our industry. Both types of agreements may include transportation charges. One type of agreement is a netback agreement, under which we sell crude oil and natural gas at the wellhead and receive a price, net of transportation expense incurred by the purchaser. In this case, we record crude oil and natural gas revenue at the net price we received from the purchaser. In the case of NGLs, we may receive a price from the purchaser, which is net of processing costs. In this case, we record NGL revenue at the net price we receive from the purchaser. The second type of agreement is one whereby we pay transportation expense directly. In that case, transportation expense is included within production expense in our consolidated statements of operations.

In addition, commodity prices we receive may be reduced by location basis differentials, which can be significant. As a result of both netback agreements and location basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period.

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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 September 30, 2014							
United States	67	538	25	182	$94.21	$3.41	$29.53
Equatorial Guinea [2]	29	233	—	68	98.63	0.27	—
Israel	—	262	—	44	—	5.59	—
Other International [3]	—	—	—	—	—	—	—
Total Consolidated Operations	96	1,033	25	294	95.55	3.26	29.53
Equity Investees [4]	2	—	6	8	102.02	—	62.24
Total Continuing Operations	98	1,033	31	302	$95.64	$3.26	$35.85
Three Months Ended September 30, 2013							
United States	64	489	13	159	$103.59	$3.57	$31.26
Equatorial Guinea [2]	37	257	—	80	107.67	0.27	—
Israel	—	255	—	43	—	5.08	—
Other International [3]	4	—	—	4	101.58	—	—
Total Consolidated Operations	105	1,001	13	286	104.95	3.11	31.26
Equity Investees [4]	2	—	6	7	104.45	—	64.74
Total Continuing Operations	107	1,001	19	293	$104.94	$3.11	$41.34
Nine Months Ended September 30, 2014							
United States	66	497	22	171	$96.84	$4.12	$35.39
Equatorial Guinea [2]	32	241	—	72	104.38	0.27	—
Israel	—	233	—	39	—	5.59	—
Other International [3]	3	—	—	3	104.47	—	—
Total Consolidated Operations	101	971	22	285	99.48	3.52	35.39
Equity Investees [4]	2	—	6	7	105.15	—	67.06
Total Continuing Operations	103	971	28	292	$99.58	$3.52	$47.96
Nine Months Ended September 30, 2013							
United States	61	434	15	148	$98.03	$3.64	$33.60
Equatorial Guinea [2]	31	251	—	73	106.78	0.27	—
Israel	—	196	—	33	—	5.03	—
Other International [3]	4	—	—	4	103.00	—	—

Total Consolidated Operations	96	881	15	258	101.08	3.00	33.60
Equity Investees (4)	2	—	6	8	105.03	—	67.59
Total Continuing Operations	98	881	21	266	$101.15	$3.00	$43.18

(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.

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(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 includes primarily China (through June 30, 2014). North Sea sales volumes for 2014 were de minimis.

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

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 September 30, 2013	$1,017	$286	$38	$1,341
Changes due to				
Increase (Decrease) in Sales Volumes	(85)	9	35	(41)
Increase (Decrease) in Sales Prices	(83)	15	(4)	(72)
Three Months Ended September 30, 2014	$849	$310	$69	$1,228
Nine Months Ended September 30, 2013	$2,683	$719	$135	$3,537
Changes due to				
Increase in Sales Volumes	109	73	68	250
Increase (Decrease) in Sales Prices	(44)	140	10	106
Nine Months Ended September 30, 2014	$2,748	$932	$213	$3,893

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

- lower realized prices for crude oil and condensate in the DJ Basin, deepwater Gulf of Mexico, and West Africa;
- lower sales volumes from the Aseng project, offshore Equatorial Guinea, due to natural production declines;
- lower sales volumes due to the timing of liftings in offshore Equatorial Guinea; and
- lower sales volumes due to the sale of our China assets at the end of second quarter 2014;

partially offset by:

- higher sales volumes for crude oil and condensate in the DJ Basin and Marcellus Shale.

Revenues from crude oil and condensate sales increased during first nine months of 2014 as compared with 2013 due to the following:

- higher sales volumes in the DJ Basin and Marcellus Shale attributable to our horizontal drilling program;

partially offset by:

- lower realized prices for crude oil and condensate in the deepwater Gulf of Mexico; and
- lower sales volumes due to the sale of our China assets at the end of the second quarter of 2014.

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

- higher sales volumes in the Marcellus Shale primarily attributable to our horizontal drilling program and continued ramp-up of activity;
- higher sales volumes in the Eastern Mediterranean due to the start-up of the Tamar project; and
- increases in total consolidated average realized prices primarily due to increased demand from cooler weather earlier in 2014 and higher-than-expected inventory withdrawals in the US, which increased the market price in our producing areas;

partially offset by:

- lower sales volumes due to non-core onshore US properties divested during 2013 and the first nine months of 2014.

NGL Sales – The majority of our US NGL production is currently from the DJ Basin. Additional NGL production from the Marcellus Shale added 5 MBbl/d during third quarter 2014 and 3 MBbl/d during the first nine months of 2014 as compared with 2013, primarily due to increased production from the wet gas acreage. NGL sales in the DJ Basin increased by 7 MBbl/d during the third quarter of 2014 as compared with 2013, while recent sales of non-core onshore US properties have slightly reduced sales volumes as compared with third quarter 2013. Additionally, sales prices increased 5% for the first nine months of 2014, compared to the first nine months of 2013.

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Income from Equity Method Investees We have interests in various equity method investees that operate midstream assets onshore US and West Africa. 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, activity is reflected within cash flows provided by operating activities and cash flows provided by (used in) investing activities.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2014	2013	Increase (Decrease) from Prior Year
Three Months Ended September 30,			
Production Expense	$217	$221	(2)%
Exploration Expense	217	60	N/M
Depreciation, Depletion and Amortization	460	412	12 %
General and Administrative	132	109	21 %
Gain on Divestitures	(30)	—	— %
Asset Impairments	33	63	(48)%
Other Operating (Income) Expense, Net	10	6	67 %
Total	$1,039	$871	19 %
Nine Months Ended September 30,			
Production Expense	$697	$619	13 %
Exploration Expense	350	211	66 %
Depreciation, Depletion and Amortization	1,297	1,146	13 %
General and Administrative	399	324	23 %
Gain on Divestitures	(72)	(12)	N/M
Asset Impairments	164	63	N/M
Other Operating (Income) Expense, Net	33	27	23 %
Total	$2,868	$2,378	21 %

N/M – Amount is not meaningful.

Changes in operating costs and expenses are discussed below.

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Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [1]	Total	United States	Equatorial Guinea	Israel	Other Int'l, Corporate [2]
Three Months Ended September 30, 2014						
Lease Operating Expense [3]	$4.91	$133	$79	$34	$13	$7
Production and Ad Valorem Taxes	1.64	44	44	—	—	—
Transportation and Gathering Expense	1.48	40	40	—	—	—
Total Production Expense	$8.03	$217	$163	$34	$13	$7
Three Months Ended September 30, 2013						
Lease Operating Expense [3]	$5.21	$137	$81	$30	$13	$13
Production and Ad Valorem Taxes	1.94	51	43	—	—	8
Transportation and Gathering Expense	1.26	33	32	—	—	1
Total Production Expense	$8.41	$221	$156	$30	$13	$22
Nine Months Ended September 30, 2014						
Lease Operating Expense [3]	$5.55	$432	$255	$101	$39	$37
Production and Ad Valorem Taxes	1.88	146	129	—	—	17
Transportation and Gathering Expense	1.54	119	118	—	—	1
Total Production Expense	$8.97	$697	$502	$101	$39	$55
Nine Months Ended September 30, 2013						
Lease Operating Expense [3]	$5.56	$393	$260	$77	$33	$23
Production and Ad Valorem Taxes	1.94	137	112	—	—	25
Transportation and Gathering Expense	1.26	89	86	—	—	3
Total Production Expense	$8.76	$619	$458	$77	$33	$51

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.
(2) Other International includes primarily China (through June 30, 2014).
(3) 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 third quarter 2014, total production expense decreased as compared with 2013 due to the following:

- decreased lease operating expense in the deepwater Gulf of Mexico due to lower net processing costs resulting from the Neptune spar, which we acquired in the second half 2013;
- decreased lease operating expense from the sale of our China assets at the end of the second quarter 2014; and
- decreased production and ad valorem taxes due to decreased revenues resulting from the sale of our China assets at the end of the second quarter 2014.

partially offset by:

- increased lease operating expense in the DJ Basin due to increased development activity and higher production

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

- increased lease operating expense in the DJ Basin and Marcellus Shale due to increased development activity resulting in higher production;
- increased lease operating expense offshore Equatorial Guinea primarily driven by increases in labor and FPSO expense resulting from the start up of the Alen field during the second half of 2013;
- increased lease operating expense offshore Israel primarily driven by increases in labor due to the start up of the Tamar field, which began producing at the end of first quarter 2013;
- increased production and ad valorem taxes in the DJ Basin and Marcellus Shale due to increased revenues resulting from higher production volumes and higher average realized prices; and
- increased transportation and gathering expense in the DJ Basin and Marcellus Shale due to higher production volumes from ongoing development activities;

partially offset by:

- decreased lease operating expense from sales of non-core onshore US properties in 2013;
- decreased lease operating expense from the sale of our China assets at the end of the second quarter of 2014; and
- decreased lease operating expense from natural field decline from the Mari-B field, offshore Israel.

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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 September 30, 2014					
Dry Hole Cost	$161	$79	$—	$—	$82
Seismic	22	4	12	1	5
Staff Expense	22	4	2	4	12
Other	12	12	—	—	—
Total Exploration Expense	$217	$99	$14	$5	$99
Three Months Ended September 30, 2013					
Dry Hole Cost	$(1)	$(1)	$—	$—	$—
Seismic	16	7	1	7	1
Staff Expense	33	11	2	2	18
Other	12	11	—	—	1
Total Exploration Expense	$60	$28	$3	$9	$20
Nine Months Ended September 30, 2014					
Dry Hole Cost	$163	$81	$—	$—	$82
Seismic	54	19	12	3	20
Staff Expense	90	22	6	9	53
Other	43	43	—	—	—
Total Exploration Expense	$350	$165	$18	$12	$155
Nine Months Ended September 30, 2013					
Dry Hole Cost	$22	$14	$8	$—	$—
Seismic	66	20	3	13	30
Staff Expense	91	23	6	3	59
Other	32	32	—	—	—
Total Exploration Expense	$211	$89	$17	$16	$89

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

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes the Falkland Islands and Nicaragua.

Exploration expense for the third quarter and first nine months of 2014 included:

- seismic expense related to 3D seismic acquisition in the deepwater Gulf of Mexico, Equatorial Guinea, and Falkland Islands;
- dry hole cost related to the Bright exploratory well, deepwater Gulf of Mexico, the Scotia exploratory well, offshore Falkland Islands, and other miscellaneous charges; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense for the third quarter and first nine months of 2013 included the following:

- dry hole cost related primarily to the deeper exploration objective of the second Gunflint appraisal well, deepwater Gulf of Mexico, and the side track portion of the Carla I-7 appraisal well, offshore Equatorial Guinea;
- seismic expense related to 3D seismic acquisition in the deepwater Gulf of Mexico, Cyprus, and Falkland Islands; and
- salaries and related expenses for corporate exploration and new ventures personnel.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
DD&A Expense (millions) [(1)]	$460	$412	$1,297	$1,146
Unit Rate per BOE [(2)]	$16.98	$15.67	$16.67	$16.22

(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 third quarter and first nine months of 2014 increased as compared with 2013 due to the following:

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

partially offset by:

- decrease due to sales of non-core onshore US properties in 2013; and
- decrease from natural field decline at the Mari-B, Noa and Pinnacles fields, offshore Israel.

The increase in the unit rate per BOE for the third quarter and first nine months of 2014 as compared with 2013 was due primarily to the change in mix of production. Higher-cost production volumes in the deepwater Gulf of Mexico and DJ Basin were offset by lower cost volumes produced at Tamar, offshore Israel. Lower cost volumes at Tamar replaced higher cost volumes produced from the Mari-B, Noa and Pinnacles fields.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
G&A Expense (millions)	$132	$109	$399	$324
Unit Rate per BOE [(1)]	$4.89	$4.14	$5.12	$4.59

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

G&A expense for the third quarter and first nine months of 2014 increased as compared with 2013 primarily due to additional expenses relating to personnel and office space in support of our major development projects. For example, our total number of employees increased from 2,190 at December 31, 2012, to 2,527 at December 31, 2013 and to over 2,600 at September 30, 2014.

Asset Impairment Expense Asset impairment expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2014	2013	2014	2013
Asset Impairments	$33	$63	$164	$63

See Item 1. Financial Statements – Note 2. Basis of Presentation, Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures.

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Other (Income) Expense

Other (income) expense was as follows:

(millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
(Gain) Loss on Commodity Derivative Instruments	$(385)	$157	$(74)	$69
Interest, Net of Amount Capitalized	52	46	151	104
Other Non-Operating (Income) Expense, Net	(13)	9	1	21
Total	$(346)	$212	$78	$194

(Gain) Loss on Commodity Derivative Instruments   (Gain) 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 price curves compared to the terms of our executed commodity instruments; increases in notional volumes; and the mix of instruments between NYMEX WTI, Dated Brent and NYMEX Henry Hub 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:

(millions, except unit rate)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Interest Expense, Gross	$79	$68	$238	$204
Capitalized Interest	(27)	(22)	(87)	(100)
Interest Expense, Net	$52	$46	$151	$104
Unit Rate per BOE [1]	$1.93	$1.74	$1.94	$1.47

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

The increase in interest expense, gross, for third quarter and first nine months of 2014 is due to the issuance of new senior debt in November 2013 and recent borrowings under our Credit Facility.

The increase in capitalized interest during third quarter of 2014 as compared with 2013 is primarily due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and offshore Israel. This increase is partially offset by the completion of longer cycle time major projects, such as Alen, offshore West Africa, and Tamar, offshore Israel, and the current concentration of development activity onshore US, which has more rapid well construction time.

The decrease in capitalized interest for the nine months ended September 30, 2014 is primarily due to the completion of longer cycle time major projects in 2013, such as Alen, offshore West Africa, and Tamar, offshore Israel, and the current concentration of development activity onshore US, which has more rapid well construction time.

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 third quarter and first nine months of 2014 as compared with 2013.

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Discontinued Operations

The North Sea geographical segment is reflected as discontinued operations for the first nine 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 2014.

Summarized results of discontinued operations were as follows:

(millions)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Oil and Gas Sales	$11	$32
Expenses	4	22
Income Before Income Taxes	7	10
Income Tax Expense	(3)	7
Operating (Income) Loss, Net of Tax	10	3
Gain on Sale, Net of Tax	—	55
Income From Discontinued Operations	$10	$58
Key Statistics:		
Daily Production		
Crude Oil & Condensate (MBbl/d)	1	1
Natural Gas (MMcf/d)	3	3
Average Realized Price		
Crude Oil & Condensate (Per Bbl)	$110.13	$108.51
Natural Gas (Per Mcf)	10.49	10.59

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.

On September 24, 2014, our equity method investee, CONE Gathering, contributed substantially all of its assets to a newly-formed master limited partnership, CONE Midstream, concurrently with an initial public offering of limited partner units. CONE Gathering subsequently distributed $204 million of the offering proceeds to us.

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. During third quarter 2014, we borrowed a net $300 million under our Credit Facility. 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

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opportunities as well as external factors such as commodity prices, among others. Our financial capacity, coupled with our 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. See Results of Operations above.

Cash on hand at September 30, 2014 totaled $1.2 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 would not incur material US tax. During the first nine months of 2014, we repatriated $519 million from our UK operations and $300 million from various other foreign operations. We will not incur material US tax on these repatriations.

We also evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending. 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 and/or financing scenarios for our significant natural gas discoveries offshore Eastern Mediterranean. The magnitude of these discoveries presents technical and financial challenges for us due to the large-scale development requirements. Each of these development options, including the development of Leviathan Phase 1, would require a multi-billion dollar investment and require a number of years to complete.

Pension Plan Termination We are in the process of terminating our defined benefit pension plan (pension plan). We expect to liquidate the associated pension obligation through lump-sum payments to participants or the purchase of annuities on their behalf.

As of December 31, 2013, the latest actuarial measurement date for the pension plan, the accumulated benefit obligation totaled $315 million, and the fair value of plan assets was $265 million. Therefore, we expect to make additional contributions to the plan of approximately $50 million during the period leading up to final termination and distribution to the extent necessary to fund the net obligation.

In addition, upon termination of the pension plan, all unamortized prior service cost and net actuarial loss remaining in AOCL will be charged to expense. This amount totaled approximately $95 million as of September 30, 2014. We expect pension plan termination to occur in the first half of 2015.

In coordination with the termination of the pension plan, we also amended our restoration plan to freeze the accrual of benefits effective December 31, 2013. Payments under the restoration plan will continue to be made in ordinary course without acceleration. Restoration plan participants who remain employed by us upon final liquidation and distribution of assets of the 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.

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

(millions, except percentages)	September 30, 2014	December 31, 2013
Cash and Cash Equivalents	$1,169	$1,117
Amount Available to be Borrowed Under Credit Facility [1]	3,100	4,000
Total Liquidity	$4,269	$5,117
Total Debt [2]	$5,583	$4,843
Total Shareholders' Equity	9,938	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 $1.2 billion in cash and cash equivalents at September 30, 2014, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $862 million of this cash is attributable to our foreign subsidiaries and a portion would be subject to US income taxes if repatriated.

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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 September 30, 2014, we had drawn $900 million under the Credit Facility to fund increased development activities. The weighted average interest rate on the borrowings was 1.43% at September 30, 2014. 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 September 30, 2014, the fair value of our commodity derivative assets was $111 million and we had no derivative liabilities (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 for Leviathan Phase 1.

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.

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 equal or exceed $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. 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 September 30, 2014, NYMEX Henry Hub natural gas price curve and current development plans, we forecast we will incur approximately $185 million under the CONSOL Carried Cost Obligation for 2014. The carry will be suspended again if average Henry Hub natural gas prices remain at or below $4.00 per MMBtu in any future three consecutive month period.

Marcellus Shale Firm Transportation Agreements During 2014, we signed Precedent Agreements for Firm Transportation to move 445,000 MMBtu per day of our Marcellus Shale natural gas production to various markets. Our financial commitment is approximately $1.2 billion, undiscounted, over a 15-year period, beginning in 2017.

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Cash Flows
Cash flow information is as follows:

	Nine Months Ended September 30,	
	2014	2013
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$2,703	$2,153
Investing Activities	(3,175)	(2,937)
Financing Activities	524	335
Increase (Decrease) in Cash and Cash Equivalents	$52	$(449)

Operating Activities   Net cash provided by operating activities for the first nine months of 2014 increased as compared with 2013. Slight increases in natural gas and natural gas liquids sales prices and an increase in crude oil and natural gas sales volumes were offset by decreases in crude oil sales prices, increases in production expenses and general and administrative expense. Working capital changes contributed $286 million of positive operating cash flow in the first nine months of 2014 as compared with a negative impact of $201 million in the first nine months of 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 $564 million during the first nine months of 2014 as compared with 2013, primarily due to increased major project development activity in our core areas. Investing activities included $156 million of the $204 million distribution from CONE Gathering, and we also invested $58 million in CONE Gathering, discussed below, during the first nine months of 2014. We received $312 million in proceeds from non-core asset divestitures during the first nine months of 2014, as compared with $119 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 nine months of 2014, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($63 million) and net cash proceeds from our Credit Facility ($900 million). We used cash to pay dividends on our common stock ($182 million), to repay Senior Notes that were due April 15, 2014 ($200 million), make principal payments related to capital lease obligations ($42 million) and repurchase shares of our common stock ($15 million). In comparison, during the first nine months of 2013, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($54 million). We also used cash to pay dividends on our common stock ($146 million), make principal payments related to the Aseng FPSO capital lease obligation ($31 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(millions)				
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition [1]	$42	$34	$171	$168
Exploration	191	275	419	660
Development [2]	1,056	795	2,792	2,169
Corporate and Other	28	35	118	159
Total	$1,317	$1,139	$3,500	$3,156
Other				
Investment in Equity Method Investee [3]	$18	$8	$58	$30
Increase in Capital Lease Obligations	60	18	81	54

(1) Unproved property acquisition cost for 2014 includes $55 million in the DJ Basin, $98 million in the Marcellus Shale, and $16 million in the deepwater Gulf of Mexico. Unproved property acquisition cost for 2013 were primarily related to acquisitions that strengthened our positions in the DJ Basin, Marcellus Shale, and deepwater Gulf of Mexico.

(2) Development expenditures for 2014 include drilling rig mobilization charges of $54 million, a portion of which is being billed to partners as the rig is utilized.

(3) Investment in equity method investees represents contributions to CONE Gathering 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 September 30, 2014, $900 million was outstanding under the Credit Facility, leaving $3.1 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 $4.3 billion at September 30, 2014. The weighted average interest rate on fixed-rate debt was 6.09%, with maturities ranging from March 2019 to August 2097. On April 15, 2014, we repaid $200 million of matured fixed rate debt.

Dividends We paid total cash dividends of 50 cents per share of our common stock during the first nine months of 2014 and 41 cents per share during the first nine months of 2013 (as adjusted for the 2-for-1 stock split during the second quarter of 2013).

On October 21, 2014, the Board of Directors declared a quarterly cash dividend of 18 cents per common share, which will be paid on November 17, 2014 to shareholders of record on November 4, 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 $45 million during the first nine months of 2014 and $39 million during the first nine 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 253,094 shares with a value of $15 million during the first nine months of 2014 and 248,986 shares with a value of $14 million during the first nine 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.

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At September 30, 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 asset position with a fair value of $111 million. Based on the September 30, 2014 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $10.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative asset by approximately $341 million. A hypothetical price increase of $0.50 per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $44 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 September 30, 2014, we had approximately $5.2 billion (excluding capital lease and other obligations) of long-term debt outstanding. Of this amount, $4.3 billion was fixed-rate debt with a weighted average interest rate of 6.09%. 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, $900 million at September 30, 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 are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of September 30, 2014, our cash and cash equivalents totaled approximately $1.2 billion, approximately 66% of which was invested in money market funds and short-term investments with major financial institutions. A change in the interest rate applicable to our variable-rate debt or our short term investments would have a de minimis impact. We currently have no interest rate derivative instruments outstanding. However, we may enter into interest rate derivative instruments in the future if we determine that it is necessary to invest in such instruments in order to mitigate our interest rate risk.

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 third quarter and the first nine months 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.

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

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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. In July 2014, we reached a resolution with OOG regarding the NOVs and Orders. The resolution of these proceedings did 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)
7/1/2014 - 7/31/2014	533	$71.83	—	—
8/1/2014 - 8/31/2014	1,492	70.03	—	—
9/1/2014 - 9/30/2014	710	70.99	—	—
Total	2,735	$70.63	—	—

(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 October 28, 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	Retention and Confidentiality Agreement between Noble Energy, Inc. and Charles D. Davidson dated August 14, 2014, filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: August 14, 2014) filed August 18, 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