NOBLE ENERGY INC
Form 10-Q
November 02, 2016
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, 2016

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, 2016, there were 429,701,812 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,	
	2016	2015	2016	2015
Revenues				
Oil, Gas and NGL Sales	$882	$783	$2,411	$2,264
Income from Equity Method Investees	28	36	70	60
Total	910	819	2,481	2,324
Costs and Expenses				
Production Expense	274	247	820	715
Exploration Expense	125	203	376	308
Depreciation, Depletion and Amortization	621	539	1,859	1,444
General and Administrative	95	109	293	308
Other Operating Expense, Net	45	188	66	310
Total	1,160	1,286	3,414	3,085
Operating Loss	(250)	(467)	(933)	(761)
Other Expense (Income)				
(Gain) Loss on Commodity Derivative Instruments	(55)	(267)	53	(331)
Interest, Net of Amount Capitalized	86	71	242	183
Other Non-Operating (Income) Expense, Net	(1)	(12)	3	(20)
Total	30	(208)	298	(168)
Loss Before Income Taxes	(280)	(259)	(1,231)	(593)
Income Tax (Benefit) Provision	(137)	24	(486)	(180)
Net Loss Including Noncontrolling Interests	(143)	(283)	(745)	(413)
Less: Net Income Attributable to Noncontrolling Interests	1	—	1	—
Net Loss Attributable to Noble Energy	$(144)	$(283)	$(746)	$(413)
Net Loss Attributable to Noble Energy Per Share of Common Stock				
Loss Per Share, Basic	$(0.33)	$(0.67)	$(1.73)	$(1.05)
Loss Per Share, Diluted	$(0.33)	$(0.67)	$(1.73)	$(1.05)
Weighted Average Number of Shares Outstanding				
Basic	430	420	430	392
Diluted	430	420	430	392

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Loss Including Noncontrolling Interests	$(143)	$(283)	$(745)	$(413)
Other Items of Comprehensive Loss				
Net Change in Mutual Fund Investment	—	—	—	(11)
Less Tax Expense	—	—	—	3
Net Change in Pension and Other	1	69	2	94
Less Tax Benefit	(1)	(23)	(1)	(33)
Other Comprehensive Income	—	46	1	53
Comprehensive Loss Including Noncontrolling Interests	(143)	(237)	(744)	(360)
Less: Comprehensive Income Attributable to Noncontrolling Interests	1	—	1	—
Comprehensive Loss Attributable to Noble Energy	$(144)	$(237)	$(745)	$(360)

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, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,819	$ 1,028
Accounts Receivable, Net	486	450
Commodity Derivative Assets	120	582
Other Current Assets	352	216
Total Current Assets	2,777	2,276
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	30,372	31,220
Property, Plant and Equipment, Other	919	858
Total Property, Plant and Equipment, Gross	31,291	32,078
Accumulated Depreciation, Depletion and Amortization	(12,186)	(10,778)
Total Property, Plant and Equipment, Net	19,105	21,300
Other Noncurrent Assets	587	620
Total Assets	$ 22,469	$ 24,196
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 786	$ 1,128
Other Current Liabilities	742	677
Total Current Liabilities	1,528	1,805
Long-Term Debt	7,854	7,976
Deferred Income Taxes	2,103	2,826
Other Noncurrent Liabilities	1,139	1,219
Total Liabilities	12,624	13,826
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; 1 Billion Shares Authorized; 471 Million and 470 Million Shares Issued, respectively	5	5
Additional Paid in Capital	6,417	6,360
Accumulated Other Comprehensive Loss	(32)	(33)
Treasury Stock, at Cost; 38 Million Shares	(696)	(688)
Retained Earnings	3,851	4,726
Noble Energy Share of Equity	9,545	10,370
Noncontrolling Interests	300	—
Total Equity	9,845	10,370
Total Liabilities and Equity	$ 22,469	$ 24,196

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,	
	2016	2015
Cash Flows From Operating Activities		
Net Loss Including Noncontrolling Interests	$(745)	$(413)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,859	1,444
Asset Impairments	—	43
Dry Hole Cost	105	154
Undeveloped Leasehold Impairment	81	—
Gain on Extinguishment of Debt	(80)	—
Loss on Asset Due to Terminated Contract	44	—
Deferred Income Tax Benefit	(699)	(244)
Loss (Gain) on Commodity Derivative Instruments	53	(331)
Net Cash Received in Settlement of Commodity Derivative Instruments	454	683
Stock Based Compensation	61	69
Non-cash Pension Termination Expense	—	81
Other Adjustments for Noncash Items Included in Income	92	74
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	6	370
Decrease in Accounts Payable	(124)	(248)
Increase (Decrease) in Current Income Taxes Payable	82	(118)
Other Current Assets and Liabilities, Net	(72)	(28)
Other Operating Assets and Liabilities, Net	(63)	(50)
Net Cash Provided by Operating Activities	1,054	1,486
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,164)	(2,519)
Cash Acquired in Rosetta Merger	—	61
Additions to Equity Method Investments	(8)	(86)
Proceeds from Divestitures and Other	786	151
Net Cash Used in Investing Activities	(386)	(2,393)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(129)	(214)
Proceeds from Issuance of Noble Energy Common Stock, Net of Offering Costs	—	1,112
Proceeds from Issuance of Noble Midstream Common Units, Net of Offering Costs	299	—
Proceeds from Term Loan Facility	1,400	—
Repayment of Credit Facility	—	(74)
Repayment of Senior Notes	(1,383)	(12)
Repayment of Capital Lease Obligation	(39)	(49)
Other	(25)	(11)
Net Cash Provided by Financing Activities	123	752
Increase (Decrease) in Cash and Cash Equivalents	791	(155)
Cash and Cash Equivalents at Beginning of Period	1,028	1,183
Cash and Cash Equivalents at End of Period	$1,819	$1,028

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

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

	Attributable to Noble Energy						
	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Non-controlling Interests	Total Equity
December 31, 2015	$5	$ 6,360	$ (33)	$ (688)	$4,726	$ —	$10,370
Net (Loss) Income	—	—	—	—	(746)	1	(745)
Stock-based Compensation	—	57	—	—	—	—	57
Dividends (30 cents per share)	—	—	—	—	(129)	—	(129)
Issuance of Noble Midstream Common Units, Net of Offering Costs	—	—	—	—	—	299	299
Other	—	—	1	(8)	—	—	(7)
September 30, 2016	$5	$ 6,417	$ (32)	$ (696)	$3,851	$ 300	$9,845
December 31, 2014	$4	$ 3,624	$ (90)	$ (671)	$7,458	$ —	$10,325
Net Loss	—	—	—	—	(413)	—	(413)
Rosetta Merger	1	1,528	—	—	—	—	1,529
Stock-based Compensation	—	69	—	—	—	—	69
Dividends (54 cents per share)	—	—	—	—	(214)	—	(214)
Issuance of Noble Energy Common Stock, Net of Offering Costs	—	1,112	—	—	—	—	1,112
Other	—	9	53	(20)	—	—	42
September 30, 2015	$5	$ 6,342	$ (37)	$ (691)	$6,831	$ —	$12,450

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 (DJ Basin, Marcellus Shale, Eagle Ford Shale, and Permian Basin), and offshore in deepwater Gulf of Mexico, Eastern Mediterranean and West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (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, 2016 and December 31, 2015 and for the three and nine months ended September 30, 2016 and 2015 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, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016.

In third quarter 2016, Noble Midstream Partners LP (Noble Midstream), a subsidiary of Noble Energy, completed its initial public offering of common units. As a result, we will be presenting our consolidated financial statements with a noncontrolling interest section representing the public's ownership in Noble Midstream. Noble Midstream and the initial public offering of common units are further discussed in Note 3. Noble Midstream Partners LP.

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, 2015.

Consolidation Our consolidated accounts include our accounts, the accounts of subsidiaries which Noble Energy wholly owns, and the accounts of Noble Midstream, which is considered a variable interest entity (VIE) for which Noble Energy is the primary beneficiary. 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.

Consolidated VIE Noble Energy has determined that the partners with equity at risk in Noble Midstream lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact Noble Midstream's economic performance; therefore, Noble Midstream is considered a VIE. Through Noble Energy's ownership interest in Noble Midstream GP LLC (the General Partner to Noble Midstream), Noble Energy has the authority to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to Noble Midstream. Therefore, Noble Energy is considered the primary beneficiary and consolidates Noble Midstream.

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.

Issuance of Phantom Units On February 1, 2016, we issued cash-settled awards to certain employees under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan in lieu of a portion of restricted stock and stock options. We issued approximately one million awards (so called phantom units, the nomenclature used in accounting literature), a portion of which are subject to the achievement of specific performance goals. These phantom units, once vested, are settled in cash. The phantom units represent a hypothetical interest in the Company. The phantom unit value is the lesser of the fair market value of a share of common stock of the Company as of the vesting date or up to four times the fair market value of a share of common stock of the Company, which was $31.65, as of the grant date.

The Company recognizes the value of our cash-settled awards utilizing the liability method as defined under Accounting Standards Codification Topic 718, Compensation - Stock Compensation. The fair value of liability awards is remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. As of September 30, 2016, the fair value remeasurement had a de minimis impact on our consolidated statement of operations and balance sheet. See Note 8. Fair Value Measurements and Disclosures.

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Notes to Consolidated Financial Statements

Recently Issued Accounting Standards In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-02 (ASU 2016-02): Leases. The guidance requires lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by leases with terms of more than 12 months. This ASU also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. We are currently evaluating the provisions of this guidance to determine the effects it will have on our consolidated financial statements and related disclosures. In the normal course of business, we enter into capital and operating lease agreements to support our exploration and development operations and lease assets such as drilling rigs, platforms, storage facilities, field services and well equipment, pipeline capacity, office space and other assets. We believe the adoption and implementation of this ASU will likely have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09 (ASU 2016-09): Compensation - Stock Compensation, to reduce complexity and enhance several aspects of accounting and disclosure for share-based payment transactions, including the accounting for income taxes, award forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. Certain aspects of this guidance will require retrospective application while other aspects are to be applied prospectively. We are currently evaluating the effect that the guidance will have on our consolidated financial statements and related disclosures.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13 (ASU 2016-13): Financial Instruments - Credit Losses, which replaces the incurred loss impairment methodology in current US GAAP with a methodology that reflects expected credit losses. The update is intended to provide financial statement users with more useful information about expected credit losses. The amended guidance is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the effect, if any, that the guidance will have on our consolidated financial statements and related disclosures. Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11 (ASU 2015-11): Simplifying the Measurement of Inventory, effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost or net realizable value. We follow the average cost method and do not believe adoption of ASU 2015-11 will have a material impact on our financial position and results of operations.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, Revenue from 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 standard will be effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. In March 2016, the FASB released certain implementation guidance through ASU 2016-08 to clarify principal versus agent considerations. We are continuing to evaluate the provisions of ASU 2014-09 and have not yet determined the full impact it may have on our financial position and results of operations. At a minimum, we expect we will be required to change from the entitlements method, used for certain domestic natural gas sales, to the sales method of accounting. We believe the impact of utilizing the sales method of accounting for our current domestic natural gas sales agreements will be de minimis.

In March 2016, the FASB issued Accounting Standards Update No. 2016-07 (ASU 2016-07): Investments - Equity Method and Joint Ventures, to eliminate retroactive application of equity method accounting when an investment becomes qualified for equity method accounting as a result of an increase in the level of ownership interest or degree of influence. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. We do not believe adoption of this guidance will have a material impact on our consolidated financial statements and related disclosures as all material investments are accounted for under the equity method of accounting.

In August 2016, the FASB issued Accounting Standards Update No. 2016-15 (ASU 2016-15): Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments, to clarify how certain cash receipts and cash payments should be presented in the statement of cash flows. Specifically, ASU 2016-15 provides additional guidance for certain cash flow items which may impact our presentation and classification within our statement of cash flows, including debt prepayments or debt extinguishment costs and distributions received from equity method investees. ASU 2016-15 will be effective for annual and interim periods beginning after December 15, 2017, with earlier application permitted. We do not believe adoption of ASU

2016-15 will have a material impact on our statement of cash flows and related disclosures as this update pertains to classification of items and is not a change in accounting principle.

In February 2015, the FASB issued Accounting Standards Update No. 2015-02 (ASU 2015-02): Consolidation - Amendments to the Consolidation Analysis, which changes the guidance as to whether an entity is a variable interest entity (VIE) or a voting interest entity and how related parties are considered in the VIE model. During third quarter 2016, Noble Midstream closed on its initial public offering of common units. In accordance with ASU 2015-02, Noble Midstream is considered a VIE as Noble Energy is considered the primary beneficiary. We have adopted the provisions of ASU 2015-02, which did not have a material effect on our financial statements or related disclosures.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2016	2015	2016	2015
Production Expense				
Lease Operating Expense	$131	$133	$412	$419
Production and Ad Valorem Taxes	30	28	73	89
Transportation and Gathering Expense (1)	113	86	335	207
Total	$274	$247	$820	$715
Other Operating (Income) Expense, Net				
(Gain) Loss on Asset Due to Terminated Contract (2)	$(3)	$—	$44	$—
Marketing and Processing Expense, Net (3)	20	10	58	25
Loss on Divestitures	—	—	23	—
Corporate Restructuring Expense	—	21	—	39
Purchase Price Allocation Adjustment (4)	—	—	(25)	—
Gain on Extinguishment of Debt (5)	—	—	(80)	—
Asset Impairments	—	—	—	43
Inventory Adjustment (6)	14	—	14	—
Building Exit Cost	4	18	8	18
Rosetta Merger Expenses	—	71	—	73
Pension Plan Expense	—	67	—	88
Stacked Drilling Rig Expense	3	13	8	20
Other, Net	7	(12)	16	4
Total	$45	$188	$66	$310
Other Non-Operating Expense (Income), Net				
Deferred Compensation Expense (Income) (7)	$2	$(13)	$7	$(19)
Other (Income) Expense, Net	(3)	1	(4)	(1)
Total	$(1)	$(12)	$3	$(20)

(1) Certain of our revenue received from purchasers was historically presented with deductions for transportation, gathering, fractionation or processing costs. Beginning in 2016, we have changed our presentation of revenue to no longer include these expenses as deductions from revenue. These costs are now included within production expense. Prior year amounts of $18 million and $37 million for the three and nine months ended September 30, 2015 have been reclassified to conform to the current presentation.

(2) Amount relates to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance. See Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs and Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview - Exploration Program Update.

(3) For the three and nine months ended September 30, 2016, amount includes $12 million and $39 million, respectively, of expense due to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.

Prior year amounts of $6 million and $15 million for the three and nine months ended September 30, 2015, were previously presented within production expense. These amounts have been reclassified to conform to the current presentation.

(4)

Amount relates to an adjustment recorded to the purchase price allocation related to the Rosetta Merger. See Note 5. Rosetta Merger.

(5) Amount relates to the tendering of senior notes assumed in the Rosetta Merger. See Note 7. Debt.

(6) Amount relates to an adjustment of inventory to its net realizable value.

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	September 30, 2016	December 31, 2015
Accounts Receivable, Net		
Commodity Sales	$ 317	$ 298
Joint Interest Billings	66	20
Proceeds Receivable [1]	40	—
Other	86	151
Allowance for Doubtful Accounts	(23)	(19)
Total	$ 486	$ 450
Other Current Assets		
Inventories, Materials and Supplies	$ 75	$ 92
Inventories, Crude Oil	25	23
Assets Held for Sale [2]	214	67
Prepaid Expenses and Other Current Assets	38	34
Total	$ 352	$ 216
Other Noncurrent Assets		
Investments in Unconsolidated Subsidiaries	$ 460	$ 453
Mutual Fund Investments	83	90
Commodity Derivative Assets	—	10
Other Assets	44	67
Total	$ 587	$ 620
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 121	$ 166
Commodity Derivative Liabilities	27	—
Income Taxes Payable	168	86
Asset Retirement Obligations	128	128
Interest Payable	93	83
Current Portion of Capital Lease Obligations	61	53
Other	144	161
Total	$ 742	$ 677
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$ 232	$ 217
Asset Retirement Obligations	820	861
Production and Ad Valorem Taxes	35	68
Commodity Derivative Liabilities	8	—
Other	44	73
Total	$ 1,139	$ 1,219

(1) Amount relates to proceeds to be received from our farm-out of 35% interest in Block 12 offshore Cyprus. See Note 4. Divestitures.

(2) Assets held for sale at September 30, 2016 primarily include $127 million relating to our 3% working interest in the Tamar project, offshore Israel, and certain producing and undeveloped assets in the DJ Basin and Eagle Ford Shale, onshore US. Assets held for sale at December 31, 2015 include the Karish and Tanin natural gas discoveries, offshore Israel. See Note 4. Divestitures.

Note 3. Noble Midstream Partners LP

Noble Midstream Partners LP In December 2014, we formed Noble Midstream Partners LP, a growth-oriented Delaware master limited partnership, to own, operate, develop and acquire a wide range of domestic midstream infrastructure assets. Noble Midstream's current areas of focus are in the DJ Basin in Colorado and in the Delaware Basin within the Permian Basin in Texas.

Initial Public Offering of Noble Midstream Partners LP On September 15, 2016, Noble Midstream common units began trading on the New York Stock Exchange under the symbol "NBLX." On September 20, 2016, Noble Midstream completed its public offering of 14,375,000 common units representing limited partner interests in Noble Midstream, which included 1,875,000 common units issued pursuant to the underwriters' exercise of their option to purchase additional common units, at a price to the public of $22.50 per common unit ($21.21 per common unit, net of underwriting discounts).

In exchange for the contributed assets, Noble Energy received:

- 1,527,584 common units, representing a 4.8% limited partner interest in Noble Midstream;
- 15,902,584 subordinated units, representing an approximate 50.0% limited partner interest in Noble Midstream;
- incentive distribution rights in Noble Midstream; and
- the right to receive a cash distribution from Noble Midstream.

In addition and concurrent with the closing of the offering, the General Partner retained a non-economic general partnership interest in Noble Midstream, which is not entitled to receive cash distributions.

Noble Midstream generated net proceeds of $299 million from the issuance of common units to the public, after deducting the underwriting discount, structuring fees and estimated offering expenses of $24 million. In third quarter 2016, Noble Midstream made a distribution of $297 million to Noble Energy.

Note 4. Divestitures

Onshore US Properties During the first nine months of 2016, we entered into certain onshore transactions for which we:

- entered into a purchase and sale agreement for the divestiture of certain producing and non-producing crude oil and natural gas interests covering approximately 33,100 net acres in the DJ Basin for $505 million, subject to customary closing adjustments. We have received proceeds of $486 million and expect to receive the remaining proceeds, subject to post-close adjustments, in mid-2017. Proceeds received were applied to the field's basis with no recognition of gain or loss;
- closed the divestiture of our Bowdoin property in northern Montana, generating proceeds of $43 million, and recognized a $23 million loss on sale of assets;
- closed a cashless acreage exchange within the DJ Basin to receive approximately 11,700 net acres within our Wells Ranch development area of the field in exchange for approximately 13,500 net acres primarily from our Bronco area of the field. No gain or loss was recognized for the transaction; and
- sold certain other non-producing interests within the DJ Basin, generating net proceeds of $20 million, and other certain smaller onshore US property packages, resulting in net proceeds of $19 million, during the first nine months of 2016. Proceeds received were applied to the respective field's basis with no recognition of gain or loss.

Subsequent to third quarter 2016, we closed the divestiture of certain Eagle Ford assets that were classified as assets held for sale of $68 million as of September 30, 2016. Total proceeds received will be applied to the field's basis with no recognition of gain or loss.

During the first nine months of 2015, we sold certain onshore US crude oil and natural gas interests in the DJ Basin, generating net proceeds of $151 million. Proceeds were applied to the field's basis with no recognition of gain or loss.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with a partner for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, for $171 million. In first quarter 2016, we received proceeds of $131 million related to the farm-out agreement and expect to receive the remaining consideration of $40 million, subject to post-close adjustments, in 2017. The proceeds were applied to the Cyprus project asset with no gain or loss recognized.

Offshore Israel Assets On July 4, 2016, we signed a definitive agreement to divest a 3% working interest in the Tamar field, offshore Israel, for $369 million, subject to customary closing adjustments. Under the terms of the agreement, the purchaser has the option to elect, before closing, to purchase an additional 1% working interest at the same valuation. The divestiture has an effective date of January 1, 2016 and is expected to close in fourth quarter 2016.

In November 2015, we executed an agreement to divest our 47% interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields, for a total transaction value of $73 million. These assets were held for sale as of December 31, 2015, and the transaction closed in January 2016.

Note 5. Rosetta Merger

On July 20, 2015, Noble Energy completed the merger of Rosetta Resources Inc. (Rosetta) into a subsidiary of Noble Energy (Rosetta Merger). The results of Rosetta's operations since the merger date are included in our consolidated statements of operations. The merger was effected through the issuance of approximately 41 million shares of Noble Energy common stock in exchange for all outstanding shares of Rosetta common stock using a ratio of 0.542 of a share of Noble Energy common stock for each share of Rosetta common stock and the assumption of Rosetta's liabilities, including approximately $2 billion fair value of outstanding debt. The merger added two new onshore US shale positions to our portfolio including approximately 50,000 net acres in the Eagle Ford Shale and 54,000 net acres in the Permian Basin (45,000 acres in the Delaware Basin and 9,000 acres in the Midland Basin). In connection with the Rosetta Merger, we incurred merger-related costs in 2015 of approximately $81 million, including (i) $66 million of severance, consulting, investment, advisory, legal and other merger-related fees, and (ii) $15 million of noncash share-based compensation expense, all of which were expensed and were included in Other Operating (Income) Expense, Net.

Allocation of Purchase Price The merger has been accounted for as a business combination, using the acquisition method. The following table represents the final allocation of the total purchase price of Rosetta to the assets acquired and the liabilities assumed based on the fair value at the merger date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill.

The following table sets forth our final purchase price allocation:

	(in millions, except stock price)
Shares of Noble Energy common stock issued to Rosetta shareholders	41
Noble Energy common stock price on July 20, 2015	$ 36.97
Fair value of common stock issued	$ 1,518
Plus: Fair value of Rosetta's restricted stock awards and performance awards assumed	10
Plus: Rosetta stock options assumed	1
Total purchase price	1,529
Plus: Liabilities assumed by Noble Energy	
Accounts Payable	100
Current Liabilities	37
Long-Term Debt	1,992
Other Long Term Liabilities	23
Asset Retirement Obligation	27
Total purchase price plus liabilities assumed	$ 3,708

Fair Value of Rosetta Assets	
Cash and Equivalents	$ 61
Other Current Assets	76
Derivative Instruments	209
Oil and Gas Properties	
Proved Reserves	1,613
Undeveloped Leaseholds	1,355
Gathering & Processing Assets	207
Asset Retirement Obligation	27
Other Property Plant and Equipment	5
Long Term Deferred Tax Asset	17
Goodwill [1]	138
Total Asset Value	$ 3,708

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(1) As of December 31, 2015, our preliminary purchase price allocation reflected goodwill of $163 million based on the fair value of assets acquired and liabilities assumed at the Rosetta Merger date. In conducting our goodwill impairment test as of December 31, 2015, we determined that our goodwill balance was no longer recoverable and fully impaired it, resulting in a goodwill impairment charge in fourth quarter 2015. In second quarter 2016, we finalized the purchase price allocation and recorded a $25 million gain to Other Operating Expense, Net driven by adjustments made based on the filing of the final Rosetta federal income tax return for the period ending on the Rosetta Merger date.

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the merger and represent Level 2 inputs. 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. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs.

The fair value measurements of crude oil and natural gas properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital. These inputs required significant judgments and estimates by management at the time of the valuation and were the most sensitive and subject to change.

The results of operations attributable to Rosetta are included in our consolidated statements of operations beginning on July 21, 2015. Revenues of $119 million and $333 million and pre-tax net loss of $4 million and $17 million were generated from Rosetta assets during the three and nine months ended September 30, 2016, respectively.

Proforma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Rosetta and gives effect to the merger as if it had occurred on January 1, 2015. The below information reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) adjustments to conform Rosetta's historical policy of accounting for its crude oil and natural gas properties from the full cost method to the successful efforts method of accounting, (ii) depletion of Rosetta's fair-valued proved crude oil and natural gas properties, and (iii) the estimated tax impacts of the pro forma adjustments. The pro forma results of operations do not include any cost savings or other synergies that may result from the Rosetta Merger or any estimated costs that have been or will be incurred by us to integrate the Rosetta assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Rosetta Merger taken place on January 1, 2015; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2016 [1]	2015	2016 [1]	2015
Revenues	$910	$846	$2,481	$2,619
Net Loss Attributable to Noble Energy	$(144)	$(202)	$(746)	$(338)
Net Loss Attributable to Noble Energy Per Share of Common Stock				
Basic	$(0.33)	$(0.44)	$(1.73)	$(0.79)
Diluted	$(0.33)	$(0.44)	$(1.73)	$(0.79)

(1)

No pro forma adjustments were made for the period as the acquisition is included in the Company's historical results.

Note 6. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil, natural gas and natural gas liquids pricing. 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.

While these instruments mitigate the cash flow risk of future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices. See Note 8. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

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Unsettled Commodity Derivative Instruments As of September 30, 2016, the following crude oil derivative contracts were outstanding:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2016	Call Option [1]	NYMEX WTI	5,000	$ —	$ —	$ —	$ 54.16
2016	Swaps	NYMEX WTI	16,000	67.69	—	—	—
2016	Swaps [2]	[3]	6,000	90.28	—	—	—
2016	Two-Way Collars	NYMEX WTI	10,000	—	—	40.50	53.42
2016	Three-Way Collars	NYMEX WTI	8,000	—	54.50	65.63	79.03
2016	Swaps	Dated Brent	9,000	97.96	—	—	—
2016	Three-Way Collars	Dated Brent	8,000	—	72.60	85.25	101.79
1H17 [4]	Swaps	NYMEX WTI	6,000	55.08	—	—	—
1H17 [4]	Two-Way Collars	NYMEX WTI	2,000	—	—	40.00	50.44
1H17 [4]	Swaps	Dated Brent	3,000	62.80	—	—	—
2H17 [4]	Call Option [1]	NYMEX WTI	3,000	—	—	—	60.12
2H17 [4]	Swaptions [5]	Dated Brent	3,000	—	—	—	62.80
2H17 [4]	Swaptions [5]	NYMEX WTI	3,000	—	—	—	50.05
2017	Two-Way Collars	NYMEX WTI	7,000	—	—	40.00	53.29
2017	Call Option [1]	NYMEX WTI	3,000	—	—	—	57.00
2017	Swaptions [5]	NYMEX WTI	4,000	—	—	—	47.34
2017	Three-Way Collars	NYMEX WTI	15,000	—	36.63	46.33	60.68
2017	Three-Way Collars	Dated Brent	2,000	—	35.00	45.00	66.33
2018	Three-Way Collars	Dated Brent	3,000	—	40.00	50.00	70.41

(1) We have entered into crude oil derivative enhanced swaps with strike prices that are above the market value as of trade commencement. To effect the enhanced swap structure, we sold call options to the applicable counterparty to receive the above market terms.

(2) Includes derivative instruments assumed by our subsidiary, NBL Texas, LLC, in connection with the Rosetta Merger.

(3) The indices for these derivative instruments are NYMEX WTI and Argus LLS.

(4) We have entered into crude oil swap contracts for portions of 2017 resulting in the difference in hedge volumes for the full year.

(5) We have entered into certain derivative contracts (swaptions), which give counterparties the option to extend with similar terms for an additional 6-month or 12-month period.

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As of September 30, 2016, the following natural gas derivative contracts were outstanding:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2016	Swaps	NYMEX HH	70,000	3.24	—	—	—
2016	Two-Way Collars	NYMEX HH	30,000	—	—	3.00	3.50
2016	Three-Way Collars	NYMEX HH	90,000	—	2.83	3.42	3.90
2016	Swaps [1]	[2]	30,000	4.04	—	—	—
2016	Two-Way Collars [1]	[2]	30,000	—	—	3.50	5.60
1H17	Swaps	NYMEX HH	30,000	2.92	—	—	—
2H17	Swaptions [3]	NYMEX HH	30,000	—	—	—	2.92
2017	Swaps	NYMEX HH	30,000	3.15	—	—	—
2017	Swaptions [3]	NYMEX HH	60,000	—	—	—	3.14
2017	Three-Way Collars	NYMEX HH	180,000	—	2.50	2.93	3.58
2017	Two-Way Collars	NYMEX HH	70,000	—	—	2.93	3.32
2018	Three-Way Collars	NYMEX HH	70,000	—	2.50	2.80	3.76

(1) Includes derivative instruments assumed by our subsidiary, NBL Texas, LLC, in connection with the Rosetta Merger.
(2) The index for these derivative instruments is Houston Ship Channel.
(3) We have entered into certain natural gas derivative contracts (swaptions), which give counterparties the option to extend with similar terms for an additional 6-month or 12-month period.

Fair Value Amounts and Loss (Gain) 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, 2016		December 31, 2015		September 30, 2016		December 31, 2015	
(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	$ 120	Current Assets	$ 582	Current Liabilities	$ 27	Current Liabilities	$ —
	Noncurrent Assets	—	Noncurrent Assets	10	Noncurrent Liabilities	8	Noncurrent Liabilities	—
Total		$ 120		$ 592		$ 35		$ —

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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)	2016	2015	2016	2015
Cash Received in Settlement of Commodity Derivative Instruments				
Crude Oil	$(119)	$(235)	$(395)	$(578)
Natural Gas	(13)	(42)	(59)	(98)
NGLs	—	(7)	—	(7)
Total Cash Received in Settlement of Commodity Derivative Instruments	(132)	(284)	(454)	(683)
Non-cash Portion of Loss on Commodity Derivative Instruments				
Crude Oil	80	4	441	301
Natural Gas	(3)	3	66	41
NGLs	—	10	—	10
Total Non-cash Portion of Loss on Commodity Derivative Instruments	77	17	507	352
(Gain) Loss on Commodity Derivative Instruments				
Crude Oil	(39)	(231)	46	(277)
Natural Gas	(16)	(39)	7	(57)
NGLs	—	3	—	3
Total Loss (Gain) on Commodity Derivative Instruments	$(55)	$(267)	$53	$(331)

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Note 7. Debt
Debt consists of the following:

(millions, except percentages)	September 30, 2016 Debt	Interest Rate	December 31, 2015 Debt	Interest Rate
Revolving Credit Facility, due August 27, 2020	$—	— %	$—	— %
Noble Midstream Revolving Credit Facility, due September 20, 2021	—	— %	—	— %
Capital Lease and Other Obligations	368	— %	403	— %
Term Loan Facility, due January 6, 2019	1,400	1.70 %	—	— %
8.25% Senior Notes, due March 1, 2019	1,000	8.25 %	1,000	8.25 %
5.625% Senior Notes, due May 1, 2021	379	5.625%	693	5.625%
4.15% Senior Notes, due December 15, 2021	1,000	4.15 %	1,000	4.15 %
5.875% Senior Notes, due June 1, 2022	18	5.875%	597	5.875%
7.25% Senior Notes, due October 15, 2023	100	7.25 %	100	7.25 %
5.875% Senior Notes, due June 1, 2024	8	5.875%	499	5.875%
3.90% Senior Notes, due November 15, 2024	650	3.90 %	650	3.90 %
8.00% Senior Notes, due April 1, 2027	250	8.00 %	250	8.00 %
6.00% Senior Notes, due March 1, 2041	850	6.00 %	850	6.00 %
5.25% Senior Notes, due November 15, 2043	1,000	5.25 %	1,000	5.25 %
5.05% Senior Notes, due November 15, 2044	850	5.05 %	850	5.05 %
7.25% Senior Debentures, due August 1, 2097	84	7.25 %	84	7.25 %
Total	7,957		7,976	
Unamortized Discount	(23)		(24)	
Unamortized Premium	17		113	
Unamortized Debt Issuance Costs	(36)		(36)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	7,915		8,029	
Less Amounts Due Within One Year				
Capital Lease Obligations	(61)		(53)	
Long-Term Debt Due After One Year	$7,854		$7,976	

Revolving Credit Facility Our Credit Agreement, as amended, provides for a $4.0 billion unsecured revolving credit facility (Revolving Credit Facility), which is available for general corporate purposes. The Revolving Credit Facility (i) provides for facility fee rates that range from 10 basis points to 25 basis points per year depending upon our credit rating, (ii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 90 basis points to 150 basis points depending upon our credit rating, and (iii) includes a sub-limit for letters of credit up to an aggregate amount of $500 million ($450 million of this capacity is committed as of September 30, 2016).

Noble Midstream Services Revolving Credit Facility On September 20, 2016, Noble Midstream Services, a subsidiary of Noble Midstream, entered into a credit agreement for a $350 million revolving credit facility (Noble Midstream Revolving Credit Facility). The Noble Midstream Revolving Credit Facility has a five year maturity and includes a letter of credit sublimit of up to $100 million for issuances of letters of credit. The borrowing capacity on the Noble Midstream Revolving Credit Facility may be increased by an additional $350 million subject to certain conditions and is available to fund working capital and to finance acquisitions and other capital expenditures of Noble Midstream.

Borrowings by Noble Midstream under the Noble Midstream Revolving Credit Facility bear interest at a rate equal to an applicable margin plus, at Noble Midstream's option, either:

- in the case of base rate borrowings, a rate equal to the highest of (1) the prime rate, (2) the greater of the federal funds rate or the overnight bank funding rate, plus 0.5% and (3) the LIBOR for an interest period of one month plus 1.00%;

or

- in the case of LIBOR borrowings, the offered rate per annum for deposits of dollars for the applicable interest period.

The Noble Midstream Revolving Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated leverage ratio to consolidated EBITDA and (2) consolidated interest coverage ratio (each covenant as described in the Noble Midstream Revolving Credit Facility). All obligations of Noble Midstream Services, as the borrower

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under the Noble Midstream Revolving Credit Facility, are guaranteed by Noble Midstream and all wholly-owned material subsidiaries of Noble Midstream.

Term Loan Agreement and Completed Tender Offers On January 6, 2016, we entered into a term loan agreement (Term Loan Facility) with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of $1.4 billion. Provisions of the Term Loan Facility are consistent with those in the Revolving Credit Facility. Borrowings under the Term Loan Facility may be prepaid prior to maturity without premium. The Term Loan Facility will accrue interest, at our option, at either (a) a base rate equal to the highest of (i) the rate announced by Citibank, N.A., as its prime rate, (ii) the Federal Funds Rate plus 0.5%, and (iii) a London interbank offered rate plus 1.0%, plus a margin that ranges from 10 basis points to 75 basis points depending upon our credit rating, or (b) a London interbank offered rate, plus a margin that ranges from 100 basis points to 175 basis points depending upon our credit rating. The interest rate for our Term Loan Facility is 1.70% as of September 30, 2016.

In connection with the Term Loan Facility, we launched cash tender offers for the 5.875% Senior Notes due June 1, 2024, 5.875% Senior Notes due June 1, 2022 and 5.625% Senior Notes due May 1, 2021, all of which were assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. Approximately $1.38 billion of notes were validly tendered and accepted by us, with a corresponding amount borrowed under the new Term Loan Facility. As a result, we recognized a gain of $80 million which is reflected in other operating (income) expense, net in our consolidated statements of operations.

Subsequent Event On November 1, 2016, we prepaid $850 million of borrowings under our Term Loan Facility from cash on hand.

See Note 8. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Note 8. 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 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, three-way collars, swaptions and enhanced swaps. We estimate the fair values of these instruments using 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 6. 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.

Phantom Units The fair value of phantom unit awards is measured based on the fair market value of our common stock on the date of grant. We recognize the value of these awards utilizing the liability method whereby these liability awards are remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. See Note 2. Basis of Presentation.

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

	Fair Value Measurements Using 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, 2016					
Financial Assets					
Mutual Fund Investments	$ 83	$ —	$ —	$ —	$ 83
Commodity Derivative Instruments	—	133	—	(13)	120
Financial Liabilities					
Commodity Derivative Instruments	—	(48)	—	13	(35)
Portion of Deferred Compensation Liability Measured at Fair Value	(105)	—	—	—	(105)
Portion of Stock Based Compensation Liability Measured at Fair Value	(6)	—	—	—	(6)
December 31, 2015					
Financial Assets					
Mutual Fund Investments	$ 90	$ —	$ —	$ —	$ 90
Commodity Derivative Instruments	—	600	—	(8)	592
Financial Liabilities					
Commodity Derivative Instruments	—	(8)	—	8	—
Portion of Deferred Compensation Liability Measured at Fair Value	(98)	—	—	—	(98)

(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:

Inventory Adjustment Materials and supplies inventories are stated at the lower of cost or net realizable value. For the nine months ended September 30, 2016, we recorded a downward adjustment of $14 million to reduce inventory to its estimated net realizable value.

Asset Impairments We periodically evaluate our oil and gas properties for impairment whenever events or circumstances indicate that the recorded carrying values of the assets may not be recoverable. In line with accounting standards, we use an undiscounted cash flow model as an indicator of possible impairment. Where circumstances warrant, we use a discounted cash flow model based on management's expectations of future production prior to abandonment date, commodity prices based on NYMEX WTI, NYMEX Henry Hub, and Brent futures price curves as of the date of the estimate, estimated operating and abandonment costs, and a risk-adjusted discount rate. For the nine months ended September 30, 2016, no impairment was indicated. Impairments for the nine months ended September 30, 2015 were due primarily to increases in asset carrying values associated with increases in estimated abandonment costs.

Assets Held for Sale In cases where assets meet the criteria to be classified as assets held for sale and a loss is expected, the underlying assets are written down to fair value less costs to sell. For the nine months ended September 30, 2016, we recorded a downward adjustment of $23 million to reflect the loss on divestiture of our Bowdoin property in northern Montana. See Note 4. Divestitures.

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Information about impaired assets is as follows:

	Fair Value Measurements Using 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)					
Nine Months Ended September 30, 2016					
Material and Supplies Inventory Adjustment	$ —	$ —	$ 91	$ 105	$ 14
Loss on Divestitures	—	—	42	65	23
Impaired Oil and Gas Properties	—	—	—	—	—
Nine Months Ended September 30, 2015					
Impaired Oil and Gas Properties	—	—	—	43	43

[1] Amount represents net book value at the date of assessment.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public 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.

Our Term Loan Facility is variable-rate, non-public debt. The fair value is estimated based on significant other observable inputs. As such, we consider the fair value of our Term Loan Facility to be a Level 2 measurement on the fair value hierarchy. See Note 7. Debt.

Fair value information regarding our debt is as follows:

(millions)	September 30, 2016 Carrying Amount	September 30, 2016 Fair Value	December 31, 2015 Carrying Amount	December 31, 2015 Fair Value
Long-Term Debt, Net [1]	$7,547	$7,976	$7,626	$7,105

[1] Net of unamortized discount, premium and debt issuance costs and excludes capital lease and other obligations.

Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs

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. On a quarterly basis, we review the status of suspended exploratory well costs and assess the development of these projects. 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, 2016	
Capitalized Exploratory Well Costs, Beginning of Period	$	1,353
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	83	

Divestitures and Other [1]	(143	)
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(1	)
Capitalized Exploratory Well Costs Charged to Expense [2]	(83	)
Capitalized Exploratory Well Costs, End of Period	$ 1,209	

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(1) Includes $143 million relating to our farm-down of a 35% interest in Block 12 offshore Cyprus to a new partner.
(2) Includes amounts related to contract termination offshore Falkland Islands, Dolphin 1 exploratory well offshore Israel, and Silvergate exploratory well deepwater Gulf of Mexico.

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, 2016	December 31, 2015
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 91	$ 95
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	1,118	1,258
Balance at End of Period	$ 1,209	$ 1,353
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	13	14

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The following table includes exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of September 30, 2016:

(millions)	Total by Project	Progress
Country/Project:		
Deepwater Gulf of Mexico		
Troubadour	$ 52	Evaluating development scenarios for this 2013 natural gas discovery including subsea tieback to existing infrastructure.
Katmai	97	Evaluating development scenarios for this 2014 crude oil discovery. In second quarter 2016, drilling operations at the Katmai 2 appraisal well, located in Green Canyon Block 39, were temporarily abandoned as a result of encountering high pressure in the untested fault block. We are assessing plans to progress appraisal and are evaluating tie-back options.
Offshore Equatorial Guinea Blocks I and O		
Diega (Block I) and Carmen (Block O)	240	Evaluating regional development scenarios for this 2008 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks I and O and in early 2016, we began analyzing, interpreting and evaluating the acquired seismic data.
Carla (Block O)	184	Evaluating regional development scenarios for this 2011 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks I and O and in early 2016, we began analyzing, interpreting and evaluating the acquired seismic data.
Yolanda (Block I)	22	A data exchange agreement for the 2007 Yolanda condensate and natural gas discovery has been executed between Equatorial Guinea and Cameroon. Our natural gas development team is working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options for both Yolanda and YoYo (Cameroon) discoveries.
Felicita (Block O)	45	Evaluating regional development scenarios for this 2008 gas discovery. During 2014, we conducted additional seismic activity over Blocks I and O and in early 2016, we began analyzing, interpreting and evaluating the acquired seismic data.
Offshore Cameroon		
YoYo (YoYo Block)	53	A data exchange agreement for the 2007 YoYo condensate and natural gas discovery has been executed between Equatorial Guinea and Cameroon. Our natural gas development team is working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options for both Yolanda (Equatorial Guinea) and YoYo discoveries.
Offshore Israel		
Leviathan	196	Our development plan was approved by the Government of Israel and we are engaged in natural gas marketing activities to meet both Israeli domestic and regional export demands.
Leviathan-1 Deep	84	The well did not reach the target interval in 2012. We are developing future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases.

Dalit	31	Our development plan was approved by the Government of Israel to develop this 2009 natural gas discovery with a tie-in to existing infrastructure at Tamar.
Offshore Cyprus		

Cyprus	88	During first quarter 2016, we received proceeds of $131 million from our 35% farm-down of interest with a partner in Block 12. In second quarter 2016, we submitted an updated development plan and continue to work with the Government of Cyprus to obtain approval of the development plan and the subsequent issuance of an Exploitation License. Receiving an Exploitation License will allow us and our partners to perform the necessary engineering and design studies and progress the project to final investment decision.
Other Individual Projects Less than $20 million	26	Continuing to assess and evaluate wells.
Total	$1,118	

Undeveloped Leasehold Costs

Undeveloped leasehold costs as of September 30, 2016 totaled $2.0 billion, comprising $1.9 billion related to core onshore US unproved properties, $116 million related to Gulf of Mexico unproved properties, and $32 million related to international unproved properties.

As part of our quarterly impairment review, we evaluate our exploration opportunities. If, based upon a change in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other factors, an impairment is indicated, we will record either (1) impairment expense related to individually significant leases or (2) a decrease in the valuation of our pool of individually insignificant leases.

During third quarter 2016, we completed our geological evaluation of certain deepwater Gulf of Mexico and offshore Falkland Islands leases and licenses and determined that several, representing $105 million of undeveloped leasehold cost, should be relinquished or exited. As a result, we recognized $81 million of leasehold impairment expense and recorded a $24 million decrease in our valuation pool of individually insignificant leases.

Note 10. Asset Retirement Obligations

Asset retirement obligations (ARO) consist 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)	2016	2015
Asset Retirement Obligations, Beginning Balance	$989	$751
Liabilities Incurred	5	54
Liabilities Settled	(87)	(29)
Revision of Estimate	4	79
Accretion Expense (1)	37	32
Asset Retirement Obligations, Ending Balance	$948	$887

(1) Accretion expense is included in Depreciation, Depletion and Amortization (DD&A) expense in the consolidated statements of operations.

For the nine months ended September 30, 2016   Liabilities incurred were due to new wells and facilities placed into service for onshore US and deepwater Gulf of Mexico. Liabilities settled were related to wells and facilities permanently abandoned at the end of their useful life and primarily included activities for Gulf of Mexico of $42 million and onshore US of $40 million.

For the nine months ended September 30, 2015   Liabilities incurred were due to new wells and facilities for onshore US and deepwater Gulf of Mexico as well as liabilities assumed in the Rosetta Merger. Liabilities settled primarily

related to non-core, onshore US properties sold.
Revisions were primarily due to changes in estimated costs for future abandonment activities and acceleration of timing of abandonment and included $43 million for Eastern Mediterranean and $28 million for DJ Basin.

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Note 11. Loss Per Share
Noble Energy's basic loss per share of common stock is computed by using net loss attributable to Noble Energy divided by the weighted average number of shares of Noble Energy common stock outstanding during each period. The following table summarizes the calculation of basic and diluted loss per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except per share amounts)	2016	2015	2016	2015
Net Loss Attributable to Noble Energy	$(144)	$(283)	$(746)	$(413)
Weighted Average Number of Shares Outstanding, Basic [1]	430	420	430	392
Weighted Average Number of Shares Outstanding, Diluted[2]	430	420	430	392
Loss Per Share, Basic	$(0.33)	$(0.67)	$(1.73)	$(1.05)
Loss Per Share, Diluted	(0.33)	(0.67)	(1.73)	(1.05)
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	14	14	15	11

(1) The weighted average number of shares outstanding includes the weighted average shares of common stock issued in connection with the underwritten public offering of 24.15 million shares of Noble Energy common stock in first quarter 2015 and issued in connection with the exchange of approximately 41 million shares for all outstanding shares of Rosetta common stock on July 20, 2015.

(2) For all periods, all outstanding options and non-vested restricted shares have been excluded from the calculation of diluted loss per share as Noble Energy incurred a net loss. Therefore, inclusion of outstanding options and non-vested restricted shares in the calculation of diluted loss per share would be anti-dilutive.

Note 12. Income Taxes
The income tax benefit consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2016	2015	2016	2015
Current	$148	$(45)	$213	$64
Deferred	(285)	69	(699)	(244)
Total Income Tax (Benefit) Provision	$(137)	$24	$(486)	$(180)
Effective Tax Rate	48.9 %	(9.3)%	39.5 %	30.4 %

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2015, we no longer consider our foreign subsidiaries' undistributed earnings to be indefinitely reinvested outside the US and, accordingly, we now record additional deferred income taxes, net of estimated foreign tax credits.
Effective Tax Rate (ETR) At the end of each interim period, we apply a forecasted annualized effective tax rate (ETR) to current year earnings or loss before tax, which can result in significant interim ETR fluctuations. Our ETR for the three and nine months ended September 30, 2016, varied as compared with the three and nine months ended September 30, 2015, resulting in a higher income tax benefit and ETR primarily due to:

- a higher loss before income taxes for the first nine months of 2016 as compared with the first nine months of 2015;
- a period to period shift of the individual components of net income (loss) among tax jurisdictions with different rates, which is also impacted by the timing and magnitude of divestiture activities. See Note 4. Divestitures and Note 13. Segment Information; and

- the change in our permanent reinvestment assumption, noted above, which resulted in additional deferred income tax expense (net of estimated foreign tax credits) being recorded on certain income items, including income from equity method investees and increased earnings in our foreign jurisdictions with rates that vary from the US statutory rate, which reduced the income tax benefit.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2013, Equatorial Guinea – 2011 and Israel – 2011.

Note 13. 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 (which includes consolidated accounts of Noble Midstream); West Africa (Equatorial Guinea, Cameroon, Gabon and Sierra Leone (which we exited in second quarter 2015)); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, Falkland Islands, Suriname, Nicaragua (which we exited in first quarter 2015) and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended September 30, 2016					
Revenues from Third Parties	$ 882	$639	$93	$ 150	$ —
Income from Equity Method Investees	28	8	20	—	—
Total Revenues	910	647	113	150	—
DD&A	621	539	46	23	13
Gain on Commodity Derivative Instruments	(55)	(48)	(7)	—	—
(Loss) Income Before Income Taxes	(280)	(407)	47	135	(55)
Three Months Ended September 30, 2015					
Revenues from Third Parties	$ 783	$510	$120	$ 152	$ 1
Income from Equity Method Investees	36	16	20	—	—
Total Revenues	819	526	140	152	1
DD&A	539	437	67	22	13
Gain on Commodity Derivative Instruments	(267)	(187)	(80)	—	—
(Loss) Income Before Income Taxes	(259)	(189)	98	107	(275)
Nine Months Ended September 30, 2016					
Revenues from Third Parties	$ 2,411	$1,705	$299	$ 407	$ —
Income from Equity Method Investees	70	39	31	—	—
Total Revenues	2,481	1,744	330	407	—
DD&A	1,859	1,612	150	62	35
Loss on Divestitures	23	23	—	—	—
Loss on Commodity Derivative Instruments	53	44	9	—	—
(Loss) Income Before Income Taxes	(1,231)	(882)	74	290	(713)
Nine Months Ended September 30, 2015					
Revenues from Third Parties	$ 2,264	$1,448	$432	$ 378	$ 6
Income from Equity Method Investees	60	35	25	—	—
Total Revenues	2,324	1,483	457	378	6
DD&A	1,444	1,138	223	52	31
Gain on Commodity Derivative Instruments	(331)	(231)	(100)	—	—
(Loss) Income Before Income Taxes	(593)	(353)	195	227	(662)
September 30, 2016					
Total Assets	$ 22,469	$17,752	$1,975	$ 2,515	$ 227
December 31, 2015					
Total Assets	24,196	18,831	2,299	2,677	389

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Note 14. 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 (CONSOL Carried Cost Obligation). The remaining obligation totaled approximately $1.6 billion at September 30, 2016.
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. The funding has been suspended since November 2014 due to lower natural gas prices. Based on the September 30, 2016 NYMEX Henry Hub natural gas price curve, we expect that the CONSOL Carried Cost Obligation will be suspended for the next 12 months.
On October 29, 2016, we entered into an agreement with CONSOL to separate ownership of our jointly owned Marcellus Shale acreage, satisfy and extinguish the remaining balance of our carried cost obligation and terminate the joint development agreement. See Part II. Other Information, Item 5. Other Information.
Delivery and Firm Transportation Commitments We have commitments to deliver approximately 493 Bcf of natural gas produced onshore US (primarily in the Marcellus Shale) under long-term sales contracts and have also entered into various long-term gathering, processing and transportation contracts for approximately 271 MMBbls of crude oil and nearly 6 Tcf of natural gas for certain of our onshore US production (primarily in the Marcellus Shale, DJ Basin and Eagle Ford Shale).
We enter into long-term contracts to provide production flow assurance in over-supplied basins and/or areas with limited infrastructure. This strategy provides for optimization of transportation and processing costs. As properties are undergoing development activities, we may experience temporary delivery or transportation shortfalls until production volumes grow to meet or exceed the minimum volume commitments. For the three and nine months ended September 30, 2016, we incurred expense of approximately $12 million and $39 million, respectively, related to deficiencies and/or unutilized commitments. We expect to continue to incur deficiency and/or unutilized costs in the near-term as development activities continue. Should commodity prices continue to decline or if we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes and we could be required to make payments in the event that these commitments are not otherwise offset.
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.
Colorado Air Matter In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream crude oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the Court on June 2, 2015.
The Consent Decree, which alleges violations of the Colorado Air Pollution Prevention and Control Act and Colorado's federal approved State Implementation Plan, specifically Colorado Air Quality Control Commission Regulation Number 7, requires us to perform certain injunctive relief activities and to complete mitigation projects and supplemental environmental projects (SEP), and pay a civil penalty. Costs associated with the settlement consist of $4.95 million in civil penalties which were paid in 2015. Mitigation costs of $4.5 million and SEP costs of $4 million are being expended in accordance with schedules established in the Consent Decree. Costs associated with the injunctive relief are not yet precisely quantifiable as they will be determined in accordance with the outcome of evaluations on the adequate design, operation, and maintenance of certain aspects of tank systems to handle potential peak instantaneous vapor flow rates between now and mid-2017.
Compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries. The Consent Decree sets forth a detailed compliance schedule with

deadlines for achievement of milestones through early 2019. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that which is required under existing Colorado regulations. Inspection and monitoring findings may influence decisions to temporarily shut in or permanently plug and abandon wells and associated tank batteries.

We have concluded that the penalties, injunctive relief, and mitigation expenditures that resulted from this settlement did not have, and based on currently available information will not have, a material adverse effect on our financial position, results of operations or cash flows.

Colorado Air Compliance Order on Consent In December 2015, we received a proposed Compliance Order on Consent (COC) from the Colorado Department of Public Health and Environment's Air Pollution Control Division (APCD) to resolve allegations of noncompliance associated with certain engines subject to various General Permit 02 conditions and/or individual permit conditions as well as certain emission control devices subject to various individual permit conditions that applied to assets currently owned and operated by both Noble Energy and Noble Midstream Services, LLC. In May, 2016, Noble Energy on behalf of itself and its wholly owned subsidiary Noble Midstream Services, LLC, on behalf of itself and its wholly owned subsidiary Colorado River DevCo LP, reached a final resolution with the APCD, which requires completion of compliance testing, modification of certain permits, payment of a civil penalty of $44,695, and an expenditure of no less than $178,780 on an approved SEP. This resolution is not believed to 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 globally diversified explorer and producer of crude oil, natural gas and natural gas liquids (NGLs). We aim to achieve sustainable growth in value and cash flow through the development of a high-quality portfolio of assets with investment flexibility. Our core operating areas include: onshore US, primarily the DJ Basin, Marcellus Shale, Eagle Ford Shale and Permian Basin; offshore US Gulf of Mexico; West Africa; and Eastern Mediterranean. In these areas, we believe we have a strategic competitive advantage and will generate attractive returns throughout oil and gas business cycles.

Our portfolio is further complemented through the pursuit of certain exploration opportunities as we seek to establish potential new core areas, such as Suriname and Gabon. We may conclude that an exploration area is not commercially viable and, therefore, may exit locations, such as we did in 2015 with Nevada, Sierra Leone and Nicaragua.

The following discussion highlights significant operating and financial results for third quarter 2016. This discussion includes operating results associated with our Rosetta Merger, which closed in third quarter of 2015, and should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2015, which includes disclosures regarding our critical accounting policies as part of "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Third Quarter 2016 Significant Operating Highlights Included:

- maintained cost reduction efforts in capital, lease operating expense and general and administrative areas, with sustained efforts to further optimize operational performance in the current commodity price environment (see Cost Reduction Efforts, below);
- averaged quarterly total sales volumes of 425 MBoe/d, net, including 270 MBoe/d, net, from onshore US assets;
- completed the initial public offering of Noble Midstream common units and generated net proceeds of $299 million;
- completed an acreage exchange which further enhances our Wells Ranch position in Colorado;
- continued to enhance well completion designs across our onshore US assets leading to capital efficiencies;
- initiated production on our fourth operated well in the Permian Basin;
- set a quarterly sales volume record of 313 MMcfe/d, net, in Israel, primarily reflecting seasonal demand and increased use of natural gas over coal to fuel power generation;
- reached a cumulative gross production milestone of one trillion cubic feet from our Tamar field since initial production in first quarter 2013;
- continued to work towards a final investment decision of our Leviathan field, including the execution of a natural gas sales agreement with NEPCO (defined below) of up to approximately 120 MMcf/d, net to Noble;
- entered into an agreement for the divestiture of 3% working interest in the Tamar field for $369 million;

commenced production in July 2016 from our Gunflint field, deepwater Gulf of Mexico, which contributed 6 MBoe/d, net, during the quarter;

- assumed operatorship of the Thunder Hawk Production Facility which processes production from our Big Bend and Dantzler fields in the Gulf of Mexico; and
- completed hook-up and commissioning activities at the Alba B3 compression project, offshore Equatorial Guinea, which commenced production in July 2016.

Third Quarter 2016 Financial Results Included:

- net loss of $144 million, as compared with net loss of $283 million for third quarter 2015;
- net gain on commodity derivative instruments of $55 million, as compared with net gain on commodity derivative instruments of $267 million for third quarter 2015;

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- reduced lease operating expense unit costs by 12% as compared to third quarter 2015, driven by increased sales volumes and cost efficiencies;
- reduced general and administrative expense unit costs by 22% as compared to third quarter 2015, driven by a decline in total costs as a result of continued cost reduction initiatives and increased sales volumes;
- recorded $81 million of exploration expense due to the write-off of certain leases and licenses in the Gulf of Mexico and offshore Falkland Islands;
- diluted loss per share of $0.33, as compared with diluted loss per share of $0.67 for third quarter 2015;
- cash flow provided by operating activities of $614 million, as compared with $520 million for third quarter 2015;
- cash proceeds from divestitures of $19 million, as compared with none for third quarter 2015; and
- capital expenditures of $297 million, as compared with $664 million for third quarter 2015.

Quarter-End Key Financial Metrics Included:

- ending cash balance of $1.8 billion, as compared with $1.0 billion at December 31, 2015;
- total liquidity of approximately $5.8 billion at September 30, 2016, as compared with $5.0 billion at December 31, 2015; and
- ratio of debt-to-book capital of 45% at September 30, 2016, as compared with 43% at December 31, 2015.

Initial Public Offering of Noble Midstream Partners LP

On September 20, 2016, Noble Midstream completed its initial public offering of common units. Noble Midstream owns, operates and will develop certain of our DJ Basin crude oil, natural gas and water-related midstream infrastructure and will also develop crude oil and produced water midstream infrastructure in our Delaware position of the Permian Basin. Noble Energy owns the general partner interest in Noble Midstream and retains a majority of limited partnership interests in the master limited partnership.

Impact of Current Commodity Prices on our Business

In early 2016, we saw crude oil trading below $30 per barrel and natural gas trading for less than $2 per MMBtu. By mid-year 2016, commodity prices slowly began to increase, with crude oil prices trading between $40 to $50 per barrel and natural gas trading between $2 to above $3 per MMBtu. While both crude oil and natural gas prices have shown signs of modest improvement since March 2016, the global economy, related supply and demand and inventory levels for such commodities indicate a continued range-bound but volatile price environment.

In response to the commodity price environment, we have taken a disciplined approach to our 2016 capital program by focusing on long-term value creation, optimizing allocation of capital and driving operational and cost efficiencies across our asset portfolio. Our current 2016 capital spending program accommodates an investment level of less than $1.5 billion, approximately 50% lower than 2015 and approximately 70% lower than 2014. See Operating Outlook – 2016 Capital Investment Program, below.

Positioning for the Future

We have taken steps to sustain our business in the current volatile commodity price environment. We have undertaken a comprehensive effort to maintain strong liquidity and balance sheet, manage our capital investment and asset portfolio and maximize operational returns, particularly through use of existing infrastructure; to this end, we have:

- allocated capital towards areas with the most favorable returns at current prices, including focusing resources towards onshore US and Eastern Mediterranean activities, while complementing our capital program through proceeds from asset divestitures;
- hedged a portion of our future revenues for 2016 to 2018 in order to mitigate the effects of commodity price volatility;
- adjusted the quarterly dividend to 10 cents per common share beginning in first quarter 2016, representing a reduction of 8 cents, or 44%, from 2015 quarterly dividend levels;
- engaged in debt refinancing activities in first quarter 2016 by tendering for certain outstanding notes and refinanced with a lower cost three year loan (1.70% as of September 30, 2016). In late 2015, we also extended our Revolving Credit Facility maturity date from 2018 to 2020;
- completed our initial public offering of Noble Midstream common units which provided access to capital markets to support funding of our onshore US midstream investment program; and
- prepaid $850 million of borrowings under our Term Loan Facility from cash on hand in November 2016.

We believe we are well positioned to address a volatile commodity price environment, and have positioned the Company for sustainable value creation, financial strength and flexibility, improved capital and operational efficiency, and long-term success throughout the oil and gas business cycle. However, if industry conditions were to persist in the range below $40 per barrel, or becomes more severe, we could experience additional material negative impacts on our production revenues, asset values,

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profitability, cash flows, liquidity and proved reserves. In response, we may consider further reductions in our capital program or dividends, and additional asset sales and/or more organizational changes. Our production and our stock price could decline further as a result of these potential developments.

Cost Reduction Efforts

We continue to focus on maintaining a strong safety culture, driving operational efficiencies, increasing productivity and leveraging the current commodity price environment to reduce our cost structure. Cost reduction initiatives, including operational enhancements, reduction of overhead costs and new pricing arrangements with suppliers, have resulted in total lease operating expense and general and administrative expense decreases as compared to third quarter 2015 and first nine months of 2015 while sales volumes increased nearly 50 MBoe/d, or 12%, and 90 MBoe/d, or 27%, respectively, compared to the same periods in prior year. Our initiatives and focused efforts overall have lead to declining unit costs for the respective comparable periods. In addition, we have applied integrated development plan learnings from other onshore US assets to realize cost efficiencies, enhance completion designs and to optimize well placement, thereby positively impacting costs and performance associated with our Texas assets, which were acquired in mid-2015.

In addition, our onshore and global portfolio provides significant optionality, which has allowed us to reduce our capital program by approximately 50% in 2016, as compared to 2015. As the majority of our onshore US assets are held by production, our portfolio flexibility allows us to invest at levels appropriate to the current commodity price environment.

Sales Volumes

On a barrel of oil equivalent basis, or BOE, total sales volumes were 12% higher for third quarter 2016 as compared with third quarter 2015, and our mix of sales volumes was 44% global liquids, 34% US natural gas and 22% international natural gas. On a BOE basis and excluding the impact of the Rosetta Merger, total sales volumes were 8% higher for third quarter 2016 as compared with third quarter 2015, and our mix of sales volumes was 40% global liquids, 34% US natural gas and 26% international natural gas. See Results of Operations – Revenues, below.

Commodity Price Changes

Crude oil prices are driven by global crude oil supply and demand factors. Since 2014, crude oil has become oversupplied as production from both OPEC and non-OPEC producers has increased, while global crude oil demand growth was curtailed by lower global economic growth, especially in Europe and developing countries, coupled with slower growth in China driven by the country's continuing economic reform. The outlook for crude oil prices for the remainder of 2016 and beyond depends primarily on supply and demand dynamics and geopolitical and security concerns in crude oil-producing nations. With OPEC production output reaching new peaks, the group announced in September 2016 its intention to limit future production in an attempt to re-balance the market. OPEC's commitment and ability to enforce this initiative, as well as Russia and other international emerging crude oil producers agreeing to freeze or curtail production, is not yet evident and may not materialize. On the demand side, recent projections reflect an increase in anticipated global crude oil demand growth as consumption increases in both India and China.

Longer term, we expect supply and demand to re-balance as global economies expand. With commodity prices experienced in early 2016, many producers reduced capital investments which will, over time, reduce production and stored inventory levels, helping to balance supply and demand in the crude oil market.

We plan for commodity price cyclicality in our business and believe we are well positioned to withstand current and future commodity price volatility due to the following:

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- we have a high-quality, globally diversified portfolio of assets, the majority of which are held by production and provide investment flexibility;
- we have hedged a portion of our domestic natural gas and global liquids sales volumes through 2018;
- we have significantly reduced our capital investment program which has allowed us to respond to the low commodity price conditions in 2016;
- we have achieved substantial cost reductions impacting both operating expenses and capital expenditures;
- we have adjusted our quarterly dividend to 10 cents per common share; and
- we have robust liquidity of approximately $5.8 billion at September 30, 2016 and ability to access capital markets.

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 reached.

DJ Basin (Onshore US) During the quarter, we operated two drilling rigs, drilled 23 wells and commenced production on 43 wells. In third quarter 2016, we closed an acreage exchange agreement to receive approximately 11,700 net acres within our Wells Ranch development area of the field in exchange for approximately 13,500 net acres primarily from our Bronco area of the field, located southwest of Wells Ranch. The exchange enhances our ability to develop the field by improving our contiguous acreage position, increasing our lateral length potential and optimizing our access to central gathering facilities.

During second quarter 2016, we entered into an agreement to divest approximately 33,100 producing and undeveloped net acres in the Greeley Crescent area of Weld County, Colorado for $505 million, representing approximately 8% of our total DJ Basin acreage. We received partial proceeds of $486 million in second quarter 2016 and expect to receive the remaining proceeds in mid-2017.

Both of these transactions facilitate our asset monetization and allow for the acceleration of asset development. We continue to improve and enhance our completion designs, and as a result, we were able to deliver production at lower capital and lease operating expense costs than third quarter of 2015.

Marcellus Shale (Onshore US) Currently, we have no operated or non-operated rigs running in the Marcellus Shale. For 2016, we and CONSOL have agreed to operate within cash flow and have agreed to a plan which will focus on well completions. As such, our allocated capital to be invested in the Marcellus Shale is limited to the completion of certain previously-drilled wells primarily located in non-operated dry gas areas. In third quarter 2016, our joint venture partner completed six wells and no wells commenced production during the quarter.

Eagle Ford Shale and Permian Basin (Onshore US) During third quarter 2016, our Eagle Ford Shale activity was focused within Gates Ranch where we operated one drilling rig, drilled five horizontal wells and commenced production on five wells. In the Permian Basin, we operated one drilling rig, drilled one horizontal well, and commenced production from one well which targeted the Upper Wolf Camp A bench. We have continued improving our completion designs and are applying best practices from our other onshore US operations, including utilizing slickwater and hybrid gel as completion fluids and testing varying cluster spacing, lateral lengths and proppant quantities. For the remainder of 2016, we are adding one rig each in the Eagle Ford Shale and the Permian Basin for a total of two rigs in each basin, as we plan to increase activity in these plays heading into 2017.

Gunflint (Deepwater Gulf of Mexico) Gunflint (31% operated working interest) was a 2008 crude oil discovery, utilizing a two-well subsea tieback to the third-party owned Gulfstar One Production Facility. Production commenced in July 2016 and contributed 6 MBoe/d, net, during third quarter 2016.

Alba Field (Offshore Equatorial Guinea) The Alba B3 compression platform was successfully installed in first quarter 2016. In July 2016, hook-up and commissioning activities were completed and first production commenced. The successful completion of this project extends the resource recovery life and slows the natural decline of this field.

Tamar Southwest We continue to work with the Government of Israel to obtain regulatory approval of our development plan, which is intended to utilize current Tamar infrastructure. The Government of Israel agreed, following a recommendation of the Israeli Supreme Court, to enter into mediation discussions that may resolve the dispute relating to the possible unitization of the Eran license, which is adjacent to the Tamar Southwest field. Timely development of Tamar Southwest will help reinforce the reliability for our Tamar project and support increased demand.

Unsanctioned Development Projects

Leviathan Project (Offshore Israel) Our Plan of Development was approved by the Government of Israel during second quarter 2016 and we and our partners are performing front-end engineering design (FEED) studies necessary to progress the

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project to final investment decision (project sanction). Timing of project sanction depends on numerous factors, including completion of necessary marketing activities, engineering and construction planning and availability of funds from us and our partners to invest in the project.

The marketing and development of natural gas from this asset is intended to serve both domestic demand and regional export. We are actively engaged in natural gas marketing activities and executed our third natural gas sales and purchase agreement in third quarter 2016. This agreement would supply up to 350 MMcf/d, gross, or approximately 120 MMcf/d, net to Noble, of natural gas from the Leviathan field to the National Electric Power Company Ltd. (NEPCO) of Jordan for consumption in power production facilities over a 15-year period. The execution of this agreement is subject to regulatory approvals from both Israel and Jordan. Sales to NEPCO are anticipated to commence at field startup. We expect to complete construction and field development to deliver first gas from Leviathan in as little as three years following sanction. The initial Leviathan field development will be a subsea tie-back to a shallow-water platform with a connection to the Israel Natural Gas Lines (INGL) pipeline network. See Update on Israel Natural Gas Regulatory Framework and Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.

Tamar Expansion Project (Offshore Israel) We have begun the planning phase for an expansion project which would expand Tamar field deliverability to approximately 2.1 Bcf/d, a quantity that would allow for regional export. Expansion would include a third flow line component and additional producing wells. Timing of project sanction is dependent upon progress relating to marketing efforts of these resources. See Update on Israel Natural Gas Regulatory Framework, below.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with a partner for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, for $171 million. In first quarter 2016, we received proceeds of $131 million related to the farm-out agreement and expect to receive the remaining consideration of $40 million, subject to post-close adjustments, in 2017. The proceeds were applied to the Cyprus project asset with no gain or loss recognized. We will continue to operate with a 35% interest. As part of the farm-out process, we negotiated a waiver of our remaining exploration well obligation.

During 2015, we submitted a Declaration of Commerciality and in second quarter 2016, we submitted an updated Development Plan to the Government of Cyprus. We continue to work with the Government of Cyprus to obtain approval of the development plan and the issuance of an Exploitation License for the Aphrodite field. Receiving an Exploitation License, in conjunction with securing markets for Aphrodite gas, will allow us and our partners to perform the necessary FEED studies and progress the project to final investment decision. In preparation for FEED, we and our partners are currently performing preliminary engineering and design (pre-FEED) for the potential development of Aphrodite field that, as currently planned, would deliver natural gas to potential customers in Cyprus and Egypt.

See Item 1. Financial Statements – Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs and Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.

Exploration Program Update

Our 2016 exploration budget has been substantially reduced compared to prior years as we adapt to the current pricing environment. While we are conducting limited exploratory activities in 2016, our core areas provide for exploration opportunities where we can apply new technologies and innovative drilling and completion designs to enhance field economics.

Through our drilling activities, we do not always encounter hydrocarbons. 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 will 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 Item 1. Financial Statements – Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs and Operating Outlook – Potential for

Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.

Updates on significant exploration activities are as follows:

Deepwater Gulf of Mexico   In first quarter 2016, drilling operations were completed at our Silvergate exploration well (50% operated working interest). The well did not encounter commercial hydrocarbons and was plugged and abandoned, resulting in dry hole expense of $79 million. In second quarter 2016, we spud our Katmai 2 appraisal well (38% operated working interest), located in Green Canyon Block 39, and encountered high pressure in the untested fault block. In response, we temporarily abandoned the well and are assessing plans to progress appraisal. As of September 30, 2016, we have capitalized approximately $43 million of costs associated with our Katmai 2 appraisal well.

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Offshore West Africa We are interpreting and evaluating recently acquired 3D seismic data across Equatorial Guinea Blocks I and O which will aid in advancing exploration and development opportunities, including the Diega/Carmen and Carla discoveries.

Offshore Cameroon We have an interest in approximately 167,800 undeveloped acres offshore Cameroon in our YoYo mining concession (100% operated working interest). The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options and are negotiating with the Cameroon government to convert the YoYo mining concession to a production sharing contract.

In July 2016, we relinquished our acreage position in the Tilapia block (46.67% operated working interest) to the Cameroon government which covered an area of approximately 900,000 gross acres. We continue to work with the Cameroon government to finalize our exit from this block.

Offshore Eastern Mediterranean In July 2016, the Petroleum Commissioner of Israel deemed our Dolphin 1 (39.66% operated working interest) 2011 natural gas discovery to be non-commercial. As a result, we recorded exploration expense of $26 million in second quarter 2016 due to the expiration of our exploration license. For other offshore Eastern Mediterranean updates, see Update on Israel Natural Gas Regulatory Framework, below.

Offshore Falkland Islands In 2015, we experienced material operational issues with a drilling rig while drilling the Humpback well. The same drilling rig was scheduled to drill another prospect but due to significant safety and operational concerns, the drilling contract was terminated in first quarter 2016. As a result, we expensed $44 million of capitalized rig costs relating to pre-drill activities which are reflected in other operating expense, net in the consolidated statements of operations in 2016. We have been working closely with our partners and the Falkland Islands Government to evaluate a path forward for our Rhea prospect, located in the North Falkland Basin adjacent to a third party's 2010 Sea Lion discovery, and in third quarter 2016, we received a three year extension for this license. We also held certain other licenses located in both the South and North Falkland Basins. Following completion of our geological assessment in third quarter 2016, we began the process of exiting all licenses outside of the Rhea prospect which resulted in a $25 million leasehold impairment charge in third quarter 2016. See Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.

Offshore Suriname The initial phase of exploration on Block 54 (non-operated 20% working interest) requires acquisition of a 3D seismic survey, which has been completed and is currently being processed. Following our evaluation of the seismic survey, we will determine if a commitment to a subsequent exploration phase to drill an exploration well is warranted.

Offshore Gabon We are the operator of Block F15 (60% working interest), an undeveloped, deep water area. Our exploration commitment includes a 3D seismic obligation which was acquired during second quarter 2016 and is currently being processed. Final product delivery is anticipated early 2017.

Update on Israel Natural Gas Regulatory Framework

The Natural Gas Framework (Framework), as adopted by the Government of Israel, provides clarity on numerous matters concerning resource development, including certain fiscal, antitrust and other regulatory matters, which we will rely upon to support a final investment decision and proceed with the development of these resources while ensuring economic benefits to the state of Israel and its citizens. The Framework provides for the reduction of our ownership interest in Tamar to 25% within six years, while enabling the marketing of Leviathan natural gas to Israeli customers. The development of Leviathan will substantially expand our capacity to deliver natural gas to Israel and the region, as well as provide a second source of domestic natural gas supply and redundancy of infrastructure.

In second quarter 2016, the Government of Israel adopted a new economic stability clause which does not prevent possible adverse legislation but instead provides for project economic stability in the event of certain future adverse actions. While it is possible that adoption of the new stability clause could be challenged in the Israeli Supreme Court, we believe this new clause addresses concerns raised by the Court in its March 2016 ruling and is consistent with that ruling.

Divestiture and Acreage Exchange Activities

We actively manage our asset portfolio and periodically divest assets. Proceeds from divestitures allow us to allocate capital and other resources to potentially higher-value and higher-growth areas and enhances our balance sheet

strength. We will continue to evaluate divestment opportunities of other assets within our portfolio.
See Item 1. Financial Statements – Note 4. Divestitures and Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.
Update on Regulations
US Offshore Regulatory Developments On April 14, 2016, the Bureau of Safety and Environmental Enforcement (BSEE) adopted a final rule updating requirements for blowout prevention systems and other well controls for offshore oil and gas activities conducted on the Outer Continental Shelf, including the Gulf of Mexico. Although the final rule incorporates some of

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the changes recommended by the oil and gas industry, it imposes a number of new requirements relating to well design, well control, casing, cementing, real-time well monitoring and subsea containment. For example, the new rule requires double sets of shear rams on all deepwater blowout preventers (BOPs), periodic inspections of BOPs and outside audits of equipment, and real-time well monitoring requirements. The new rule will likely increase the costs associated with well design, drilling and completion operations, and monitoring of rig based operations in the Gulf of Mexico. The final rule went into effect on July 28, 2016.

On March 17, 2016, the Bureau of Ocean Energy Management (BOEM) proposed a new air quality rule that would significantly broaden the scope of air emission sources for operations on the Outer Continental Shelf, including the Gulf of Mexico, that be must assessed, reported and when appropriate controlled. Among other items, the proposed rule would expand the types of emissions that must be measured, change the boundary for evaluating air emissions, and increase the scope of sources that must be addressed. If adopted as proposed, the new rule would likely increase the cost associated with our activities in the Gulf of Mexico. The comment period for the proposed rule expired June 20, 2016.

On July 14, 2016, the BOEM issued an updated Notice to Lessees and Operators (NTL) providing details on revised procedures the agency will be using to determine a lessee's ability to carry out decommissioning obligations for activities on the Outer Continental Shelf, including the Gulf of Mexico. This revised policy became effective September 12, 2016 and institutes new criteria by which the BOEM will evaluate the financial strength and reliability of lessees and operators active on the Outer Continental Shelf. If the BOEM determines under the revised policy that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. We estimated the impact of the new financial criteria on our operations in the Gulf of Mexico and do not believe that the revised policy will have a material impact on our operations in the Gulf of Mexico.

The National Oceanic and Atmospheric Administration (NOAA) is proposing to expand the boundaries of the Flower Garden Banks National Marine Sanctuary in the Gulf of Mexico. NOAA released its draft environmental impact statement (DEIS) on the proposed expansion in June 2016, in which it proposed five alternatives for expanding existing sanctuary regulations to new geographic areas. Two of these alternatives for sanctuary expansion have the potential to impact certain leases which could increase drilling, operating and decommissioning costs. The comment period for the expansion alternatives outlined in the DEIS expired on August 19, 2016. We are currently evaluating the expansion alternatives and assessing any potential impact on our operations in the Gulf of Mexico.

Colorado Crude Oil and Natural Gas Regulation The Colorado Oil and Gas Task Force (Task Force) was established by executive order and made up of representatives of local governments, civic entities, environmental organizations and industry for the purpose of making recommendations regarding oil and gas development in communities. The Task Force issued nine recommendations to the governor of Colorado, all of which were adopted by legislation or regulation. The Colorado Oil and Gas Conservation Commission issued new rules governing the siting of large oil and gas operations in urban areas and the coordination of drilling operations with local governments. These new rules took effect in March 2016.

Earlier in 2016, the State of Colorado approved for signature gathering, four ballot measures which, if adopted, would have significantly limited or, under certain circumstances, prevented the future development of crude oil and natural gas in areas where we conduct operations. The measures sought to grant local communities the opportunity to ban certain businesses from operating in their jurisdictions, establish a constitutional right to a healthy environment and oblige local governments to protect the environment, grant local governments control over oil and gas development and require that all new oil and gas facilities be located 2,500 feet from occupied structures.

Only two of the four ballot measures completed the signature gathering phase before the August 8, 2016 deadline. However, neither of those measures garnered the 98,492 valid signatures necessary to be included on the November 2016 ballot.

We continue to monitor proposed and new regulations and legislation in all our 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 economic and environmental benefits of safe and responsible crude oil and natural gas development.

Pennsylvania Crude Oil and Natural Gas Regulation On October 8, 2016, the Pennsylvania Department of Environmental Protection issued a final rule amending Pennsylvania Code Chapter 78a revising requirements for surface activities related to unconventional oil and gas operations. The final rule increases requirements for permitting, waste handling, water management and restoration, surface reclamation, and requirements related to abandoned and orphaned wells. These regulations may increase operating costs and cause delays.

Impact of Dodd-Frank Act Section 1504 On June 27, 2016, the SEC adopted resource extraction issuer payment disclosure rules under Section 1504 of the Dodd-Frank Act that will require resource extraction companies, such as us, to publicly file with the SEC information about the type and total amount of payments made to a foreign government, including subnational governments (such as states and/or counties), or the U.S. federal government for each project related to the commercial

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development of crude oil, natural gas or minerals, and the type and total amount of payments made to each government. Reporting and disclosure will be required annually beginning with the 2018 fiscal year.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2016 Production Our expected crude oil, natural gas and NGL production for the remainder of 2016 may be impacted by several factors including:

- commodity prices which, if subject to further decline, could result in certain current production becoming uneconomic;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, will impact near-term production volumes;
- Israeli industrial and residential demand for electricity, which is largely impacted by weather conditions and conversion of the Israeli electricity portfolio from coal to natural gas;
- timing of the divestiture of 3% working interest in the Tamar field which will lower our sales volumes;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa;
- natural field decline in the onshore US, deepwater Gulf of Mexico and offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico and Gulf Coast areas, or winter storms and flooding impacting onshore US operations;
- reliability of support equipment and facilities, pipeline disruptions, and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in production and/or mid-stream processing;
- malfunctions and/or mechanical failures at terminals or other onshore US delivery points;
- impact of enhanced completion efforts for onshore US assets;
- shut-in of US producing properties if storage capacity becomes unavailable;
- drilling and/or completion permit delays due to future regulatory changes; and
- purchases of producing properties or divestments of operating assets.

2016 Capital Investment Program Given the current commodity price environment, we designed a substantially reduced but flexible capital investment program in order to manage our balance sheet while preserving and building value. Our 2016 capital investment program accommodates an investment level of less than $1.5 billion, or approximately 50% lower than our 2015 program, with approximately two-thirds of total investment to core onshore US assets and the remaining one-third to offshore development and exploration. With our successful completion of offshore developments in the Gulf of Mexico and Equatorial Guinea in mid-2016, our capital program for the remainder of 2016 will be focused in our onshore US areas, where we receive the best returns and are able to maximize use of existing infrastructure, and progressing the development of our assets offshore Israel. For the remainder of 2016, we intend to operate two rigs in the DJ Basin and are adding one rig each in the Eagle Ford Shale and the Permian Basin for a total of two rigs in each basin, as we plan to increase activity in these plays heading into 2017. Offshore Israel, we spud our Tamar 8 development well in late October 2016 which will increase supply reliability and accelerate our development of the Tamar field.

See Liquidity and Capital Resources – Financing Activities.

Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments

Exploration Activities Our exploratory drilling program seeks to provide long-term growth from existing and potential new core areas. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. For example, in the first nine months of 2016, we recorded total dry hole expense of $105 million primarily associated with our Silvergate exploratory well in the Gulf of Mexico and our Dolphin 1 discovery offshore Israel. The Silvergate well did not encounter commercial hydrocarbons and was plugged and abandoned, and our Dolphin 1 discovery was ruled by the Petroleum Commissioner of Israel to be non-commercial. See Item 1. Financial Statements - Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs and Results of Operations - Oil and Gas Exploration Expense, below.

Additionally, we may not conduct exploration activities prior to lease expirations. For example, in the deepwater Gulf of Mexico, we continue to mature our prospect portfolio. However, 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. In addition, the current commodity price environment may render certain prospects economically less attractive and we may not conduct exploration activities before lease expiration. During third quarter 2016, we accelerated our geological evaluation of certain of these leases and determined that several of them should be relinquished. As a result, we recorded $56 million of leasehold impairment expense related to

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certain of our deepwater Gulf of Mexico leases. During third quarter 2016, we also completed our geological assessment of licenses located in the South and North Falkland Basins near the Falkland Islands. Following completion of our geological assessment in third quarter 2016, we began the process of exiting all licenses outside of the Rhea prospect which resulted in a $25 million leasehold impairment charge in third quarter 2016.

We currently have remaining capitalized undeveloped leasehold cost of approximately $116 million relating to deepwater Gulf of Mexico prospects that have not yet been drilled and are scheduled to expire over the years 2017 to 2026. Changes in exploration plans, availability of capital and suitable rig and drilling equipment, insufficient resource potential, changing regulations and/or other factors, could result in future impairment. Moreover, in the deepwater Gulf of Mexico, some leases may become impaired for other reasons such as production not being established, foregoing actions to extend the terms of the leases, and/or leases becoming uneconomic due to commodity prices or the rising costs of complying with new regulations.

As a result of our exploration activities, future exploration expense, including leasehold expense, could be significant. See Results of Operations - Oil and Gas Exploration Expense, below. See also Item 1A. Risk Factors.

Development Concept Selection Costs   For our Leviathan and Cyprus discoveries, full field development may require several phases, with various facilities serving both domestic and regional export demand. In order to determine an optimum development scenario for these discoveries, we and our partners engage in development planning, also known as pre-FEED and FEED studies. Furthermore, we may progress pre-FEED and FEED studies simultaneously for multiple development options, with the realization that only one option may ultimately be approved or be economically feasible. This simultaneous progression of multiple options enables us to advance a final investment decision and quality development of resources in a timely and efficient manner.

Conducting pre-FEED and FEED work to varying degrees for a range of phased development scenarios may result in our incurring significant charges, as compared with pre-FEED and FEED costs incurred for previous offshore projects where the resources were not as significant. Other factors that may increase our pre-FEED and FEED costs include location of a field in a remote and/or under-developed area, lack of availability of, or capacity at, third party production platforms or other infrastructure, technical complexity, market availability, and significant time and effort required for government approval.

Once the final development plan has been determined and our board of directors has sanctioned a final investment decision, we expect to identify certain development scenarios that must be eliminated from further consideration. As a result, final investment decision for our Leviathan project may result in the write-off of pre-FEED and FEED costs, estimated at approximately $100 million, pre-tax, as of September 30, 2016. Pre-FEED and FEED costs are included in our capitalized development well cost balances.

Producing Properties We did not recognize any material impairments during the nine months ended September 30, 2016. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future crude oil and natural 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 commodity prices, or widening of basis differentials, alone could result in an impairment.

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 also be difficult to estimate costs of rigs and services in periods of fluctuating demand. In addition, we do not operate certain assets and we therefore work with respective operators to receive updated estimates of abandonment activities and costs. For example, the operator of the MacCulloch North Sea field has notified working interest owners that the scope and magnitude of decommissioning activities has been revised downward, resulting in a potentially accelerated project timeline with lower field abandonment costs. As of September 30, 2016, we had a total asset retirement obligation of $84 million related to this remediation project. As the operator moves beyond the initial decommissioning phase, we will continue to monitor the status and costs of the project and will adjust our estimate accordingly. See Item 1. Financial Statements - Note 10. Asset Retirement Obligations.

Divestments We actively manage our asset portfolio. 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. See Note 4. Divestitures.

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RESULTS OF OPERATIONS
Revenues
Revenues were as follows:

(millions)	2016	2015	(Decrease) / Increase from Prior Year
Three Months Ended September 30,			
Oil, Gas and NGL Sales	$882	$783	13 %
Income from Equity Method Investees	28	36	(22)%
Total	$910	$819	11 %
Nine Months Ended September 30,			
Oil, Gas and NGL Sales	$2,411	$2,264	6 %
Income from Equity Method Investees	70	60	17 %
Total	$2,481	$2,324	7 %

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 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 the case of NGLs, we may receive a price from the purchaser, which is net of fractionation and processing costs. Historically, we have recorded revenue at the net price we had received from the purchaser, net of transportation, fractionation or processing costs. Beginning in 2016, we changed our presentation of revenue to no longer include expenses netted from revenue by the purchaser. Crude oil, natural gas and NGL sales are now shown without deductions relating to transportation, fractionation or processing. These deductions are now recorded as production expense. Prior year amounts, including revenues, expenses, average realized sales prices and average production costs per BOE, have been reclassified to conform to the current presentation. For NGL sales, amounts reclassified for the three and nine months ended September 30, 2015 totaled $18 million and $37 million, respectively. Amounts reclassified for crude oil and natural gas sales were de minimis.
In addition, commodity prices we receive may be reduced by location basis differentials, which can be significant. For example, transportation bottlenecks and oversupply in the Marcellus Shale have reduced the amount of production reaching higher priced out-of-basin locations. As a result of 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, 2016							
United States	99	874	55	299	$41.23	$ 2.38	$14.70
Equatorial Guinea [2]	22	261	—	65	43.73	0.27	—
Israel	—	310	—	52	—	5.22	—
Total Consolidated Operations	121	1,445	55	416	41.67	2.61	14.70
Equity Investees [3]	2	—	7	9	45.72	—	23.65
Total	123	1,445	62	425	$41.75	$ 2.61	$15.66
Three Months Ended September 30, 2015							
United States	83	741	49	255	$42.42	$ 2.01	$11.37
Equatorial Guinea [2]	27	231	—	65	45.99	0.27	—
Israel	—	303	—	51	—	5.39	—
Total Consolidated Operations	110	1,275	49	371	43.30	2.50	11.37
Equity Investees [3]	2	—	6	8	51.41	—	24.86
Total	112	1,275	55	379	$43.44	$ 2.50	$12.73
Nine Months Ended September 30, 2016							
United States	99	902	56	304	$37.23	$ 2.00	$13.38
Equatorial Guinea [2]	25	230	—	64	40.74	0.27	—
Israel	—	284	—	48	—	5.19	—
Total Consolidated Operations	124	1,416	56	416	37.94	2.36	13.38
Equity Investees [3]	2	—	5	7	43.95	—	24.43
Total	126	1,416	61	423	$38.02	$ 2.36	$14.32
Nine Months Ended September 30, 2015							
United States	73	658	34	217	$46.02	$ 2.20	$13.77
Equatorial Guinea [2]	29	221	—	66	52.15	0.27	—
Israel	—	254	—	43	—	5.39	—
Other International [4]	1	—	—	1	55.52	—	—
Total Consolidated Operations	103	1,133	34	327	47.79	2.54	13.77
Equity Investees [3]	2	—	5	6	51.67	—	28.77
Total	105	1,133	39	333	$47.85	$ 2.54	$15.64

(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 US natural gas and NGLs are significantly less than the price for a barrel of crude oil. In Israel, we sell natural gas under contracts where the majority of the price is fixed, resulting in less commodity price disparity between reporting periods.

(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 in part by affiliated entities accounted for under the equity method of accounting.

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

(4) Other International includes de minimis North Sea sales volumes with last production in May 2015.

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	Natural Gas	NGLs	Total
Three Months Ended September 30, 2015	$438	$ 293	$52	$783
Changes due to				
Increase in Sales Volumes	34	29	10	73
(Decrease) Increase in Sales Prices	(11)	25	12	26
Three Months Ended September 30, 2016	$461	$ 347	$74	$882
Nine Months Ended September 30, 2015	$1,352	$ 785	$127	$2,264
Changes due to				
Increase in Sales Volumes	176	185	82	443
Decrease in Sales Prices	(237)	(54)	(5)	(296)
Nine Months Ended September 30, 2016	$1,291	$ 916	$204	$2,411

Crude Oil and Condensate Sales – Revenues from crude oil and condensate sales increased for third quarter 2016 and decreased for first nine months of 2016 as compared with 2015 due to the following:

- decreases in average realized prices primarily due to the decline in global commodity prices that began in the second half of 2014; and
- natural field decline at Alen and Aseng in offshore Equatorial Guinea;

partially offset by:

- production from the Big Bend and Dantzler developments (deepwater Gulf of Mexico), which began producing fourth quarter 2015 and contributed 8 MBbl/d and 6 MBbl/d, net, respectively, during the first nine months of 2016;
- production from the Gunflint development (deepwater Gulf of Mexico), which began producing in July 2016 and contributed 4 MBbl/d, net, during the current quarter; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired third quarter 2015, which contributed 11 MBbl/d and 6 MBbl/d, net, respectively, during the first nine months of 2016.

Natural Gas Sales – Revenues from natural gas sales increased during third quarter and first nine months of 2016 as compared with 2015 due to the following:

- higher sales volumes from the Tamar field, offshore Israel, in response to the increased use of natural gas over coal to fuel power generation and higher seasonal demand;
- higher sales volumes in the Marcellus Shale due to commencement of production on 42 operated and non-operated wells, and the recognition of efficiencies in base production performance; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired third quarter 2015, which contributed 135 MMcf/d and 9 MMcf/d, net, respectively, during the first nine months of 2016;

partially offset by:

- decreases in average realized prices primarily due to the decline in global commodity prices that began in the second half of 2014.

NGL Sales – Revenues from NGL sales increased during third quarter and first nine months of 2016 as compared with 2015 due to the following:

- higher sales volumes in the DJ Basin driven by higher NGL yields due to infrastructure operating efficiencies; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired third quarter 2015, which contributed 23 MBbl/d and 1 MBbl/d, net, respectively, during the first nine months of 2016;

partially offset by:

- decreases in average realized prices primarily driven by oversupply.

Income from Equity Method Investees We have interests in 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.

Income from equity method investees increased for the first nine months of 2016 as compared with 2015. The increase includes a $9 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee; a $3 million

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decrease from Alba Plant, our LPG investee, due to lower realized prices; and an increase of $4 million from our investments in CONE Gathering LLC and CONE Midstream Partners due primarily to higher throughput volumes.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2016	2015	Increase / (Decrease) from Prior Year
Three Months Ended September 30,			
Production Expense	$274	$247	11 %
Exploration Expense	125	203	(38)%
Depreciation, Depletion and Amortization	621	539	15 %
General and Administrative	95	109	(13)%
Other Operating Expense, Net	45	188	(76)%
Total	$1,160	$1,286	(10)%
Nine Months Ended September 30,			
Production Expense	$820	$715	15 %
Exploration Expense	376	308	22 %
Depreciation, Depletion and Amortization	1,859	1,444	29 %
General and Administrative	293	308	(5)%
Other Operating Expense, Net	66	310	(79)%
Total	$3,414	$3,085	11 %

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	Corporate
Three Months Ended September 30, 2016						
Lease Operating Expense [2]	$3.42	$131	$98	$ 22	$8	$ 3
Production and Ad Valorem Taxes	0.78	30	30	—	—	—
Transportation and Gathering Expense [3]	2.95	113	113	—	—	—
Total Production Expense	$7.15	$274	$241	$ 22	$8	$ 3
Total Production Expense per BOE		$7.15	$8.77	$ 3.67	$1.67	N/M
Three Months Ended September 30, 2015						
Lease Operating Expense [2]	$3.89	$133	$92	$ 26	$13	$ 2
Production and Ad Valorem Taxes	0.83	28	28	—	—	—
Transportation and Gathering Expense [3]	2.51	86	86	—	—	—
Total Production Expense	$7.23	$247	$206	$ 26	$13	$ 2
Total Production Expense per BOE		$7.23	$8.77	$ 4.32	$2.78	N/M
Nine Months Ended September 30, 2016						
Lease Operating Expense [2]	$3.62	$413	$305	$ 75	$25	$ 8
Production and Ad Valorem Taxes	0.64	72	72	—	—	—
Transportation and Gathering Expense [3]	2.94	335	335	—	—	—
Total Production Expense	$7.20	$820	$712	$ 75	$25	$ 8
Total Production Expense per BOE		$7.20	$8.53	$ 4.30	$1.91	N/M
Nine Months Ended September 30, 2015						
Lease Operating Expense [2]	$4.70	$419	$274	$ 96	$38	$ 11
Production and Ad Valorem Taxes	1.00	89	89	—	—	—
Transportation and Gathering Expense [3]	2.32	207	207	—	—	—
Total Production Expense	$8.02	$715	$570	$ 96	$38	$ 11
Total Production Expense per BOE		$8.02	$9.61	$ 5.32	$3.27	N/M

N/M amount is not meaningful.

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

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

(3) Certain of our revenue received from purchasers was historically presented with deduction for transportation, fractionation or processing costs. Beginning in 2016, we have changed our presentation of revenue to no longer include these expenses as deductions from revenue. These costs are now included within production expense and prior year amounts have been reclassified to conform to the current presentation. See Results of Operations – Revenues, above.

For third quarter and first nine months of 2016, total production expense increased as compared with 2015 due to the following:

- an increase in transportation and gathering expense due to higher production, including the addition of onshore US production from our Eagle Ford Shale and Permian Basin assets acquired in third quarter 2015, and from our Big Bend and Dantzler development projects in deepwater Gulf of Mexico, which began producing in fourth quarter 2015, and Gunflint in deepwater Gulf of Mexico, which began producing in July 2016;

partially offset by:

- a decrease in production and ad valorem taxes resulting from lower revenues and an onshore US severance tax refund, both driven by a decline in US commodity prices.

While total production expense has increased as a result of increased production for the respective periods compared to 2015, costs on a per BOE basis have declined. We are working to maintain lease operating expense cost reductions in areas such as equipment utilization and saltwater disposal which help to optimize cost and operational efficiencies.

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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, 2016					
Leasehold Impairment and Amortization	$96	$ 71	$ —	$ —	$ 25
Dry Hole Expense	5	—	—	—	5
Seismic, Geological and Geophysical	15	—	—	—	15
Staff Expense	15	1	—	—	14
Other (4)	(6)	—	—	—	(6)
Total Exploration Expense	$125	$ 72	$ —	$ —	$ 53
Three Months Ended September 30, 2015					
Leasehold Impairment and Amortization	$41	$ 41	$ —	$ —	$ —
Dry Hole Expense	135	—	27	—	108
Seismic, Geological and Geophysical	—	—	—	—	—
Staff Expense	27	3	—	2	22
Other (4)	—	—	—	—	—
Total Exploration Expense	$203	$ 44	$ 27	$ 2	$ 130
Nine Months Ended September 30, 2016					
Leasehold Impairment and Amortization	$127	$ 102	$ —	$ —	$ 25
Dry Hole Expense	105	79	—	26	—
Seismic, Geological and Geophysical	47	—	10	—	37
Staff Expense	53	2	2	—	49
Other (4)	44	35	—	7	2
Total Exploration Expense	$376	$ 218	$ 12	$ 33	$ 113
Nine Months Ended September 30, 2015					
Leasehold Impairment and Amortization	$78	$ 73	$ —	$ 5	$ —
Dry Hole Expense	154	18	27	—	109
Seismic, Geological and Geophysical	2	2	—	—	—
Staff Expense	72	2	2	4	64
Other (4)	2	—	—	2	—
Total Exploration Expense	$308	$ 95	$ 29	$ 11	$ 173

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone (which we exited in second quarter 2015), and Gabon.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International, Corporate includes the Falkland Islands, other new ventures and corporate expenditures.

(4) Includes lease rentals and other exploratory costs.

Exploration expense for third quarter and first nine months of 2016 included:

- leasehold impairment expense primarily related to write-off of leases and licenses in the deepwater Gulf of Mexico of $56 million and Falkland Islands of $25 million;
- dry hole cost primarily related to the Silvergate exploratory well, deepwater Gulf of Mexico, and the Dolphin 1 natural gas discovery, offshore Israel;
- seismic expense related to the acquisition of 3D seismic data in West Africa and other international areas;
- other cost for onshore US includes lease rentals primarily related to Permian Basin leases; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense for third quarter and first nine months of 2015 included the following:

- dry hole cost related to onshore US, offshore Cameroon (Cheetah), and Falkland Islands (Humpback) exploration wells;
- leasehold impairment, including a $41 million deepwater Gulf of Mexico lease; 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,	
	2016	2015	2016	2015
DD&A Expense (millions) (1)	$621	$539	$1,859	$1,444
Unit Rate per BOE (2)	$16.23	$15.75	$16.31	$16.21

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

Total DD&A expense for third quarter and first nine months of 2016 increased as compared with 2015 due to the following:

- the addition of Eagle Ford Shale and Permian Basin production in third quarter 2015, resulting in $144 million and $31 million in DD&A expense, respectively, during the first nine months of 2016;
- an increase in sales volumes due to commencement of production from the Big Bend, Dantzler and Gunflint development projects in deepwater Gulf of Mexico, additional wells which came online in the Marcellus Shale and increased demand in Eastern Mediterranean; and
- a reduction in proved reserves in fourth quarter 2015 primarily due to downward price revisions in DJ Basin and Marcellus Shale;

partially offset by:

- an overall lower segment rate for offshore Equatorial Guinea due to the swing in production between higher DD&A rate assets Aseng and Alen and lower DD&A rate asset Alba; and
- the impact of lower net book value as a result of a fourth quarter 2015 impairment for offshore Equatorial Guinea properties.

The increase in the unit rate per BOE for third quarter and first nine months of 2016 as compared with 2015 was due primarily to increased higher-cost production volumes from certain onshore US properties and recently commenced deepwater Gulf of Mexico assets, Big Bend, Dantzler and Gunflint. The increase in the unit rate per BOE was partially offset by an increase in lower-cost production volumes from the Tamar and Alba fields and reductions in net book values in fourth quarter 2015 mainly due to downward price revisions.

Significant changes to the proved reserves at December 31, 2015 include additions of 269 MMBoe resulting from the Rosetta Merger during the third quarter 2015, offset by downward revisions of 307 MMBoe that were commodity price driven. Estimates of proved reserves significantly affect our DD&A expense. Holding other factors constant, a decline in proved reserves estimates caused by decreases in the 12-month average commodity prices, will result in accelerating DD&A expense in future periods.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
G&A Expense (millions)	$95	$109	$293	$308
Unit Rate per BOE (1)	$2.48	$3.19	$2.57	$3.46

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

G&A expense for third quarter and first nine months of 2016 decreased as compared with 2015 primarily due to cost savings initiatives, including reduced use of contractors and consultants, decreased special projects and other discretionary expenses, and decreases in employee personnel costs, partially offset by the addition of Rosetta employees in the third quarter of 2015. The decrease in the unit rate per BOE for the third quarter and first nine months of 2016 as compared with 2015 was due primarily to the increase in production volumes in onshore US, deepwater Gulf of Mexico, and Eastern Mediterranean, and cost synergies achieved through the Rosetta Merger.

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Other Operating (Income) Expense Other operating (income) expense was as follows:

(millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
(Gain) Loss on Asset Due to Terminated Contract	$(3)	$—	$44	$—
Marketing and Processing Expense, Net	20	10	58	25
Loss on Divestitures	—	—	23	—
Corporate Restructuring Expense	—	21	—	39
Purchase Price Allocation Adjustment	—	—	(25)	—
Gain on Extinguishment of Debt	—	—	(80)	—
Asset Impairments	—	—	—	43
Inventory Adjustment	14	—	14	—
Building Exit Cost	4	18	8	18
Rosetta Merger Expenses	—	71	—	73
Pension Plan Expense	—	67	—	88
Stacked Drilling Rig Expense	3	13	8	20
Other, Net	7	(12)	16	4
Total	$45	$188	$66	$310

See Item 1. Financial Statements – Note 2. Basis of Presentation for discussion of the above components of other operating (income) expense.

Other (Income) Expense

Other (income) expense was as follows:

(millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
(Gain) Loss on Commodity Derivative Instruments	$(55)	$(267)	$53	$(331)
Interest, Net of Amount Capitalized	86	71	242	183
Other Non-Operating Expense (Income), Net	(1)	(12)	3	(20)
Total	$30	$(208)	$298	$(168)

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments includes (i) cash settlements (received) or paid relating to our crude oil and natural gas commodity derivative contracts, respectively, and (ii) non-cash (increases) or decreases in the fair value of our crude oil and natural gas commodity derivative contracts, respectively.

Cash settlement gains for the third quarter and first nine months of 2016 were driven by crude oil and natural gas hedge contracts primarily executed in previous years when commodities were trading at higher prices. Our crude oil contracts contributed $95 million and $317 million of cash settlements and our natural gas contracts contributed $8 million and $34 million, respectively, of cash settlements received in the third quarter and first nine months of 2016. In addition, we acquired commodity derivative contracts as part of the Rosetta Merger. Acquired crude oil contracts contributed gains of $24 million and $78 million of cash settlements and acquired natural gas contracts contributed $5 million and $25 million, respectively, of cash settlements received in the third quarter and first nine months of 2016.

Non-cash decreases in the fair value of our crude oil and natural gas commodity derivative contracts of $77 million and $507 million for the third quarter and first nine months of 2016, respectively, were primarily driven by the evolving and diverse mix of derivative contracts (i.e. the type of derivative instrument, the commodity being hedged and related volumes), acquired commodity derivative contracts as part of the Rosetta Merger, and fluctuations of current period and future commodity prices.

See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities and Note 8. Fair Value Measurements and Disclosures.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except unit rate)	2016	2015	2016	2015
Interest Expense, Gross	$103	$110	$312	$294
Capitalized Interest	(17)	(39)	(70)	(111)
Interest Expense, Net	$86	$71	$242	$183
Unit Rate per BOE [(1)]	$2.25	$2.08	$2.12	$2.05

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

Interest expense, gross, was flat for third quarter 2016 as compared with 2015. The increase in interest expense, gross, for the first nine months of 2016 as compared with 2015 is primarily due to the impact of senior notes assumed by us in the Rosetta Merger during third quarter 2015, a portion of which were subsequently tendered during first quarter 2016 through proceeds derived from our Term Loan Facility. See Item 1. Financial Statements - Note 7. Debt.

The decrease in capitalized interest for third quarter and first nine months of 2016 as compared with 2015 is primarily due to lower work in progress amounts related to major long-term projects including Big Bend and Dantzler, deepwater Gulf of Mexico, which were both completed in fourth quarter 2015 and Gunflint, deepwater Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, which were both completed in July 2016. Additional items that contributed to the decrease in capitalized interest include offshore Cyprus (due to the farm-out agreement with a partner for a 35% interest in Block 12 during fourth quarter 2015), offshore Falkland Islands (due to the Humpback prospect that began drilling operations in June 2015 and was determined to be a dry hole during fourth quarter 2015), and timing of onshore US activities. See Item 1. Financial Statements - Note 9. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Income Taxes

See Item 1. Financial Statements – Note 12. Income Taxes for a discussion of the change in our effective tax rate for third quarter and first nine months of 2016 as compared with 2015.

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, including the current commodity price environment. 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 continuing exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity.

We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives. 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 Revolving Credit Facility, and proceeds from sales of non-core properties. We occasionally access the capital markets and, in third quarter 2016, we monetized certain of our midstream assets through the initial public offering of Noble Midstream common units.

Initial Public Offering of Noble Midstream Partners LP

On September 20, 2016, Noble Midstream completed its public offering of 14,375,000 common units representing limited partner interests in Noble Midstream, which included 1,875,000 common units issued pursuant to the underwriters' exercise of their option to purchase additional common units, at a price to the public of $22.50 per common unit ($21.21 per common unit, net of underwriting discounts). In connection with the offering, Noble Midstream generated net proceeds of $299 million from the issuance of common units and distributed $297 million to us.

We own a 54.8% limited partner interest and a non-economic general partner interest in Noble Midstream, while the public owns a 45.2% limited partner interest. We consolidate Noble Midstream as a variable interest entity for financial reporting purposes; however, Noble Midstream's sources of liquidity are independent of Noble Energy. See Item 1. Financial Statements – Note 2. Basis of Presentation. The public's ownership interest in Noble Midstream is reflected as a noncontrolling interest in our financial statements as of September 30, 2016.

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Noble Midstream's partnership agreement provides for a minimum quarterly distribution to the holders of common units and subordinated units of $0.3750 per unit for each whole quarter, or $1.5000 per unit on an annualized basis, to the extent Noble Midstream has sufficient available cash after the establishment of cash reserves and the payment of certain costs and expenses. We own all of Noble Midstream's subordinated units and incentive distribution rights. Upon completion of certain events as outlined in Noble Midstream's partnership agreement, we will be entitled to receive additional distributions associated with these units.

Available Liquidity Information regarding cash and debt balances as shown in the table below, does not include amounts held by Noble Midstream, which are not readily available to Noble Energy:

(millions, except percentages)	September 30, 2016	December 31, 2015
Cash and Cash Equivalents	$ 1,772	$ 1,001
Amount Available to be Borrowed Under Revolving Credit Facility [1]	4,000	4,000
Total Liquidity	$ 5,772	$ 5,001
Total Debt [2]	$ 7,957	$ 7,976
Noble Energy Share of Equity	9,545	10,370
Ratio of Debt-to-Book Capital [3]	45 %	43 %

(1) Does not include $350 million available to be borrowed under Noble Midstream's Revolving Credit Facility, which is not available to Noble Energy. See Revolving Credit Facilities, below.

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

(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 Noble Energy's share of equity.

Cash and Cash Equivalents We had approximately $1.8 billion in cash and cash equivalents at September 30, 2016, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $488 million of this cash is attributable to our foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings of $368 million for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credit. Our cash on hand at September 30, 2016 also included $47 million relating to Noble Midstream.

Revolving Credit Facilities Noble Energy's Revolving Credit Facility matures on August 27, 2020. The commitment is $4.0 billion through the maturity date of the Revolving Credit Facility. Noble Midstream's Revolving Credit Facility matures on September 20, 2021. The commitment is $350 million through the maturity date of Noble Midstream's Revolving Credit Facility. As of September 30, 2016, no amounts were outstanding under either of these facilities. Borrowings under these facilities subject us to interest rate risk. See Item 1. Financial Statements – Note 7. Debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Term Loan We occasionally access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Revolving Credit Facility or to refinance scheduled debt maturities. On January 6, 2016, we entered into the Term Loan Facility which provides for a three-year term loan facility for a principal amount of $1.4 billion. In connection with the Term Loan Facility, we launched cash tender offers for certain senior notes assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. Collectively, the result of these transactions provides for significant future interest expense savings with a shorter term debt maturity. While we have no near-term debt maturities, we may seek to access the capital markets to refinance a portion of our outstanding indebtedness. As of September 30, 2016, we had $7.5 billion of long-term debt outstanding, $2.4 billion of which is due first quarter 2019. On November 1, 2016, we prepaid $850 million of long-term debt outstanding under our Term Loan Facility from cash on hand. See Item 1. Financial Statements – Note 7. Debt.

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, three-way collars, swaptions and enhanced swaps.

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, 2016, the fair value of our commodity derivative assets was $120 million and the fair value of our commodity derivative liabilities was $35 million (after consideration of netting provisions within our master agreements).

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While we use commodity derivative instruments to mitigate our exposure to commodity price risk, thereby mitigating our exposure to price declines, these instruments may also limit our potential cash flows in periods of rising commodity prices or even place us in a liability position respective to our counterparties. For example, should commodity prices increase, certain of our swaptions are likely to be extended by our counterparties which could require us to pay monthly cash settlements if market prices exceed the contracted swap prices.
See Item 1. Financial Statements – Note 8. 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.

Asset Divestitures

In addition, we evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending and may consider non-core asset sales or other sources of funding. Furthermore, as required by the Framework, we are required to divest certain of our interests within a stipulated period of time. During the first nine months of 2016, we received cash proceeds of approximately $786 million primarily from our divestment of certain onshore US assets in the DJ Basin, our Cyprus farm-out and the sale of our Karish and Tanin discoveries, offshore Israel. On July 4, 2016, we signed a definitive agreement to divest a 3% interest in the Tamar field, offshore Israel, for $369 million, subject to customary closing adjustments. See Item 1. Financial Statements – Note 4. Divestitures.

Capital Program

Our 50% reduction in capital spending in 2016 as compared to 2015, coupled with operating efficiencies to increase production at lower costs, has allowed us to closely align capital spending with our operating cash flows. We will continue our effort to invest capital at a level supported by current operating cash flows. Our financial capacity and lack of near-term debt maturities, coupled with our diversified global portfolio, provides us with flexibility in our investment decisions including execution of major development projects and exploration activity.

Our investment program is primarily supported by production from our core onshore US development programs, combined with new production from our completed major offshore projects in the Gulf of Mexico (including the Big Bend and Dantzler development projects, which began producing in fourth quarter 2015, and from the Gunflint development, which began producing in July 2016), as well as completion of the Alba B3 compression project offshore Equatorial Guinea, which commenced production in July 2016. Presuming no significant further deterioration of commodity prices, cash flows from these assets will be available to meet a portion of our remaining 2016 capital commitments and will help to fund investments in subsequent years. See Results of Operations, above.

We are currently exploring potential financing scenarios, including use of external project financing arrangements as well as using local internal cash flows supplemented by asset divestiture proceeds, to develop our significant natural gas discoveries offshore Eastern Mediterranean. Each of our development options, including the development of Leviathan infrastructure to supply domestic and regional demands, would require a multi-billion dollar investment and require a number of years to complete. See Update on Israel Natural Gas Regulatory Framework, above.

Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedge counterparties, and financial institutions on an ongoing basis. 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. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our non-operating partners for their respective shares of joint venture costs. Our projects are capital cost intensive and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs or have liquidity problems resulting in slow payment of joint venture costs. In addition, in the event of bankruptcy or insolvency of a joint venture partner, we may be required to complete their share of remediation activities or fulfill their lease obligations which could result in significant financial losses.

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.

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. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a trade creditor, joint venture partner, hedge counterparty or financial institution could result in significant financial losses.

Contractual Obligations

Marcellus Shale Joint Development Agreement The joint development agreement for our jointly owned Marcellus Shale acreage provides for a multi-year drilling and development plan (default plan). We and CONSOL have agreed to an annual plan that provides for fewer wells to be drilled than the number of wells that was provided for in the default plan, and, for 2016, the amount of capital investment allocated to the Marcellus Shale core area will be less than the amount provided for in the default

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plan. Each of us has a non-consent right, which is the right to elect not to participate in all (but not less than all) of the operations provided for the following year. If one of us elects to exercise the non-consent right, then the other partner, in its sole discretion, may determine the number of wells, if any, it will drill in such year, which may be significantly less than the number of wells that was provided for in the default plan, or none at all. In the event we elect to exercise our non-consent right for a given year, we would still have to pay the carried costs that are contemplated by the development plan for that non-consent year. Under the joint development agreement, this non-consent right may be exercised by each partner twice (in non-consecutive years) prior to the termination of the default plan at the end of 2020. Neither of us has exercised the non-consent right, and thus, each of us may still elect to exercise the non-consent right twice (in non-consecutive years) prior to the end of 2020.

On October 29, 2016, we entered into an agreement with CONSOL to separate ownership of our jointly owned Marcellus Shale acreage, satisfy and extinguish the remaining balance of our carried cost obligation and terminate the joint development agreement. See Part II. Other Information, Item 5. Other Information.

CONSOL Carried Cost Obligation See Item 1. Financial Statements - Note 14. Commitments and Contingencies and Part II. Other Information, Item 5. Other Information

Exploration Commitments The terms of some of our production sharing contracts, licenses or concession agreements may require us to conduct certain exploration activities, including drilling one or more exploratory wells or acquiring seismic data, within specific time periods. These obligations can extend over periods of several years, and failure to conduct such exploration activities within the prescribed periods could lead to loss of leases or exploration rights.

Continuous Development Obligations Although the majority of our assets are held by production, certain of our onshore US assets are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas and failure to meet these obligations may result in the loss of a lease. Our 2016 capital program allows for managing these obligations.

Delivery and Firm Transportation Agreements We have entered into various long-term gathering, processing, transportation and delivery contracts for some of our onshore US crude oil and natural gas production. These contracts may commit us to deliver minimum volumes and require us to make payments for any shortfalls in delivering or transporting the minimum volumes under the commitments. We may use long-term contracts such as these, which may range in term from one to 40 years, to provide flow assurance for production and to enable our production to reach markets with best pricing.

Although we strive to schedule well completion activities to meet the minimum volumes under the commitments, we may experience temporary, and possibly prolonged, delivery or transportation shortfalls. During the first nine months of 2016, we incurred expense of approximately $39 million related to deficiencies and/or unutilized commitments. We expect to continue to incur deficiency and/or unutilized costs in the near-term as development activities continue. For full year 2016, we estimate these costs could range from approximately $50 million to $60 million.

Should commodity prices continue to remain low or decline further, or we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes under these commitments. In the event that these commitments are not otherwise offset, we could be required to make future payments for any shortfalls. While we continually seek to optimize under-utilized assets through capacity release and third-party arrangements, as well as, for example, through the shifting of transportation of production from rail cars to pipelines when we receive a higher netback price, we may continue to experience these shortfalls both in the near and long-term.

Credit Rating Events We do not have any triggering events on our consolidated debt that would cause a default in case of a downgrade of our credit rating. In addition, there are no existing ratings triggers in any of our commodity hedging agreements that would require the posting of collateral. However, a series of downgrades or other negative rating actions could increase our cost of financing, and may increase our requirements to post collateral as financial assurance of performance under certain other contractual arrangements such as pipeline transportation contracts, crude oil and natural gas sales contracts, work commitments and certain abandonment obligations. A requirement to post collateral could have a negative impact on our liquidity.

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Cash Flows

Cash flow information is as follows:

(millions)	Nine Months Ended September 30, 2016	2015
Total Cash Provided By (Used in)		
Operating Activities	$1,054	$1,486
Investing Activities	(386)	(2,393)
Financing Activities	123	752
Increase (Decrease) in Cash and Cash Equivalents	$791	$(155)

Operating Activities   Net cash provided by operating activities for the first nine months of 2016 decreased as compared with 2015. Decreases in average realized commodity prices and lower settlements of commodity derivative instruments were partially offset by increases in sales volumes. Working capital changes resulted in a $171 million operating cash flow reduction in the first nine months of 2016 as compared with a negative impact of $74 million in the first nine months of 2015.

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-out arrangements, which may result in reimbursement for capital spending that occurred in prior periods. Capital spending for property, plant and equipment decreased by $1.4 billion during the first nine months of 2016 as compared with 2015, primarily due to a reduced capital spending program. Investing activities included $8 million in CONE Gathering LLC during the first nine months of 2016 as compared with $86 million in the same period of 2015. We received $786 million in proceeds from asset divestitures during the first nine months of 2016, as compared with $151 million during the same period in 2015.

Financing Activities   Our financing activities include the issuance or repurchase of Noble Energy common stock and Noble Midstream common units, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first nine months of 2016, we received proceeds ($299 million) from our initial public offering of Noble Midstream common units and funds from the term loan acquisition ($1.4 billion). We used cash to pay dividends on our common stock ($129 million), fund the purchase of certain of our outstanding senior notes ($1.38 billion), and make principal payments related to capital lease obligations ($39 million).

In comparison, during the first nine months of 2015, funds were provided by cash proceeds from the issuance of Noble Energy common stock to the public ($1.1 billion). We used cash to pay dividends on our common stock ($214 million), repay outstanding borrowings under the Rosetta revolving credit facility and terminate the facility ($74 million) and make principal payments related to capital lease obligations ($49 million).

See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities

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

(millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Acquisition, Capital and Exploration Expenditures				
Property Acquisition [1]	$21	$21	$60	$86
Exploration	25	117	183	257
Development	202	458	597	1,695
Midstream [2]	9	26	29	123

Corporate and Other	38	21	58	78
Total	$295	$643	$927	$2,239
Other				
Investment in Equity Method Investee (3)	$2	$21	$8	$86
Increase in Capital Lease Obligations	5	29	5	60

(1) Property acquisition cost for 2016 includes $28 million in the DJ Basin, $22 million in the Marcellus Shale, $5 million in the Permian Basin and $5 million in the Eagle Ford Shale. Proved property acquisition cost for 2015 includes $37 million in the DJ Basin and $43 million in the Marcellus Shale.

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(2) Midstream cost for the three and nine months ended September 30, 2016 includes Noble Midstream capital expenditures of $8 million and $13 million, respectively. Midstream costs for the three and nine months ended 2015 includes Noble Midstream capital expenditures of $14 million and $49 million, respectively.

(3) Investment in equity method investee represents primarily contributions to CONE Gathering LLC which owns and operates the natural gas gathering infrastructure associated with our Marcellus Shale joint venture.

Total expenditures decreased during the first nine months of 2016 as compared with 2015 due to our reduced capital spending program. See Operating Outlook – 2016 Capital Investment Program, above.

Financing Activities

Long-Term Debt   Our principal source of liquidity is our Revolving Credit Facility that matures August 27, 2020. At September 30, 2016, there were no borrowings outstanding under the Revolving Credit Facility, leaving $4.0 billion available for use. We may rely on our Revolving Credit Facility to help fund our capital investment program, and may periodically borrow amounts for working capital purposes. On January 6, 2016, we entered into the Term Loan Facility with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of $1.4 billion. In connection with the Term Loan Facility, we launched cash tender offers for certain Senior Notes assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. On November 1, 2016, we prepaid $850 million of long-term debt outstanding under our Term Loan Facility from cash on hand. See Item 1. Financial Statements – Note 7. Debt.

Our outstanding fixed-rate debt (excluding capital lease obligations) totaled approximately $6.1 billion at September 30, 2016. The weighted average interest rate on fixed-rate debt was 5.69%, with maturities ranging from March 2019 to August 2097.

Dividends   We paid total cash dividends of 30 cents per share of common stock during the first nine months of 2016 as compared with 54 cents per share during the first nine months of 2015.

On October 25, 2016, our board of directors declared a quarterly cash dividend of 10 cents per common share, which will be paid on November 21, 2016 to shareholders of record on November 7, 2016. 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 $8 million during the first nine months of 2016 and $7 million during the first nine months of 2015.

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 235,157 shares with a value of $8 million during the first nine months of 2016 and 481,229 shares with a value of $20 million during the first nine months of 2015.

Item 3.   Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

At September 30, 2016, we had various open commodity derivative instruments related to crude oil and natural gas. 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 $85 million. Based on the September 30, 2016 published commodity futures price curves for the underlying commodities, a hypothetical price increase of 10% per Bbl for crude oil would decrease the fair value of our net commodity derivative asset by approximately $70 million. A hypothetical price increase of 10% per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $33 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 6. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our Revolving Credit Facility, Noble Midstream Revolving Credit Facility and Term Loan Facility and the amount of interest we earn on our short-term investments.

At September 30, 2016, we had approximately $7.5 billion (excluding capital lease obligations) of long-term debt, net, outstanding. Of this amount, $6.1 billion was fixed-rate debt, net, with a weighted average interest rate of 5.69%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss.

However, we are exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of September 30, 2016, our cash and cash equivalents totaled nearly $1.8 billion, approximately 65% of which was invested in money market funds and short-term investments with major financial institutions. In addition, borrowings under the Term Loan Facility are subject to variable interest rates which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. A change in the interest rate applicable to our variable-rate debt could expose us to additional interest cost. While we currently have no interest rate derivative instruments as of September 30, 2016, we may invest in such instruments in the future in order to mitigate interest rate risk. A change in the interest rate applicable to our short-term investments would have a de minimis impact.

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 three and nine months ended September 30, 2016 and 2015. 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 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, 2015 and in this quarterly report on

Form 10-Q, 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, 2015 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) and Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), are effective. There were no changes in internal control over financial reporting (as defined in Exchange Act

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Rule 13a-15(f) and 15d-15(f)) that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See discussion of legal proceedings in Part I. Financial Information, Item 1. Financial Statements - Note 14. Commitments and Contingencies of this Form 10-Q, which is incorporated by reference into this Part II. Item 1, as well as discussion in Item 3. Legal Proceedings, of our Annual Report on Form 10-K for the year ended December 31, 2015.

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, 2015, other than the following:

One of our subsidiaries acts as the general partner of a publicly traded master limited partnership, Noble Midstream, which may involve a greater exposure to legal liability than our historic business operations.

One of our subsidiaries acts as the general partner of Noble Midstream, a publicly traded master limited partnership. Our control of the general partner of Noble Midstream may increase the possibility that we could be subject to claims of breach of fiduciary duties, including claims of conflicts of interest, related to Noble Midstream. Any liability resulting from such claims could have a material adverse effect on our future business, financial condition, results of operations and cash flows.

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)
7/1/2016 - 7/31/2016	1,248	$ 35.82	—	—
8/1/2016 - 8/31/2016	462	34.91	—	—
9/1/2016 - 9/30/2016	577	34.51	—	—
Total	2,287	$ 35.31	—	—

(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
On October 29, 2016, we entered into an Exchange Agreement (the “Exchange Agreement”) with CNX Gas Company LLC, a subsidiary of CONSOL Energy Inc. (collectively, “CNX”), pursuant to which the parties will exchange interests in the oil and gas properties (including certain related assets, the “Co-Owned Properties”) that are jointly owned by us and CNX and subject to the Joint Development Agreement dated September 30, 2011, as amended (the “JDA”). The JDA provides for the joint development of the Co-Owned Properties and, in certain circumstances, requires us to fund one-third of CNX’s working interest share of certain drilling and completion costs incurred in connection with the Co-Owned Properties (the “Carried Costs”). As of October 1, 2016, the Carried Costs owed by Noble totaled $1.6 billion.

At the closing of the Exchange Agreement: (a) the remaining balance of our Carried Cost obligation will be satisfied and extinguished; (b) we will take all of CNX’s interest in a portion of the Co-Owned Properties; (c) CNX will take all of our interest in the remainder of the Co-Owned Properties; and (d) we will pay CNX $205 million in cash. The foregoing transactions are subject to certain adjustments provided for in the Exchange Agreement. The JDA will terminate effective upon the closing of the Exchange Agreement.

Following the closing of the Exchange Agreement, we will own and operate a 100% working interest in approximately 363,000 acres in the Marcellus Shale, predominantly in West Virginia, with associated average daily production of approximately 450 million cubic feet per day of natural gas equivalents for the month ended October 31, 2016.

The Exchange Agreement contains customary representations and warranties, covenants, indemnification obligations and the closing is subject to customary closing conditions. If either party terminates the Exchange Agreement because of a willful breach by the other party or the other party’s election not to close despite all of its closing conditions having been satisfied, the party terminating the Exchange Agreement is entitled to liquidated damages of $100 million from the other party.

The Exchange Agreement is expected to close on or about December 1, 2016, or if the conditions to closing identified in the Exchange Agreement have not yet been satisfied as of such date, as soon thereafter as such conditions have been satisfied or waived, but no later than January 31, 2017.

The Exchange Agreement is attached to this quarterly report on Form 10-Q as Exhibit 2.3 and is incorporated herein by reference. The foregoing summary has been included to provide information regarding the terms of the Exchange Agreement and is qualified in its entirety by the terms and conditions of the Exchange Agreement. It is not intended to provide any other factual information about us or our subsidiaries and affiliates. The Exchange Agreement contains representations and warranties, which were made by us only for purposes of the Exchange Agreement and as of specified dates. The representations, warranties and covenants in the Exchange Agreement were made solely for the benefit of the parties to the Exchange Agreement, may be subject to limitations agreed upon by the contracting parties, including being qualified by confidential disclosures made for the purposes of allocating contractual risk between the parties to the Exchange Agreement instead of establishing these matters as facts, and may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors. The representations, warranties and covenants in the Exchange Agreement, or any descriptions thereof, should not be relied upon as characterizations of the actual state of facts or condition of us or any of our subsidiaries or affiliates.

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

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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	November 2, 2016	/s/ Kenneth M. Fisher Kenneth M. Fisher Executive Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
2.1	Asset Acquisition Agreement, dated August 17, 2011, between CNX Gas Company LLC and Noble Energy, Inc. including Appendix I (Definitions) thereto (filed as Exhibit 2.1 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference).
2.2	Agreement and Plan of Merger, dated as of May 10, 2015, by and among Noble Energy, Inc., Bluebonnet Merger Sub Inc. and Rosetta Resources Inc. (filed as Exhibit 2.1 of the Registrant’s Current Report on Form 8-K (Date of Report: May 10, 2015) filed on May 11, 2015 and incorporated herein by reference).
2.3	Exchange Agreement, executed October 29, 2016, by and Between CNX Gas Company LLC and Noble Energy, Inc., filed herewith.
3.1	Restated Certificate of Incorporation of Noble Energy Inc. (filed as Exhibit 3.3 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. (as amended through July 27, 2016) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: July 27, 2016) filed on July 29, 2016 and incorporated herein by reference).
3.3	Certificate of Elimination of the Series A Junior Participating Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.1 to the Registrant’s Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.4	Certificate of Elimination of the Series B Mandatorily Convertible Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.2 to the Registrant’s Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 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), furnished 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), furnished 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