

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

FORM 10-Q

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

For the quarterly period ended September 30, 2017

OR

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

For the transition period from _____ to _____

Commission file number: 001-07964



NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of incorporation or organization)

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

1001 Noble Energy Way
Houston, Texas
(Address of principal executive offices)

77070
(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

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

Yes No

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company Emerging growth company
(Do not check if a smaller reporting company)

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of September 30, 2017, there were 486,607,284 shares of the registrant's common stock, par value \$0.01 per share, outstanding.

TABLE OF CONTENTS

Part I. Financial Information	3
Item 1. Financial Statements	3
Consolidated Statements of Operations and Comprehensive Loss	3
Consolidated Balance Sheets	4
Consolidated Statements of Cash Flows	5
Consolidated Statements of Equity	6
Notes to Consolidated Financial Statements	7
Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations	30
Item 3. Quantitative and Qualitative Disclosures About Market Risk	54
Item 4. Controls and Procedures	56
Part II. Other Information	57
Item 1. Legal Proceedings	57
Item 1A. Risk Factors	57
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	57
Item 3. Defaults Upon Senior Securities	58
Item 4. Mine Safety Disclosures	58
Item 5. Other Information	58
Item 6. Exhibits	59
Signatures	61

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues				
Oil, NGL and Gas Sales	\$ 907	\$ 882	\$ 2,918	\$ 2,411
Income from Equity Method Investees and Other	53	28	137	70
Total	960	910	3,055	2,481
Costs and Expenses				
Production Expense	280	282	866	839
Exploration Expense	64	125	136	376
Depreciation, Depletion and Amortization	523	621	1,554	1,859
Loss on Marcellus Shale Upstream Divestiture	4	—	2,326	—
General and Administrative	102	95	304	293
Other Operating (Income) Expense, Net	(15)	37	132	127
Total	958	1,160	5,318	3,494
Operating Income (Loss)	2	(250)	(2,263)	(1,013)
Other Expense				
Loss (Gain) on Commodity Derivative Instruments	22	(55)	(145)	53
Loss (Gain) on Extinguishment of Debt	98	—	98	(80)
Interest, Net of Amount Capitalized	88	86	271	242
Other Non-Operating Expense (Income), Net	2	(1)	(4)	3
Total	210	30	220	218
Loss Before Income Taxes	(208)	(280)	(2,483)	(1,231)
Income Tax Benefit	(93)	(137)	(917)	(486)
Net Loss and Comprehensive Loss Including Noncontrolling Interests	(115)	(143)	(1,566)	(745)
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	21	1	46	1
Net Loss and Comprehensive Loss Attributable to Noble Energy	\$ (136)	\$ (144)	\$ (1,612)	\$ (746)
Net Loss Attributable to Noble Energy per Common Share				
Basic and Diluted	\$ (0.28)	\$ (0.33)	\$ (3.47)	\$ (1.73)
Weighted Average Number of Common Shares Outstanding				
Basic and Diluted	487	430	464	430

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

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

	September 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	\$ 564	\$ 1,180
Accounts Receivable, Net	675	615
Other Current Assets	303	160
Total Current Assets	1,542	1,955
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	30,583	30,355
Property, Plant and Equipment, Other	928	909
Total Property, Plant and Equipment, Gross	31,511	31,264
Accumulated Depreciation, Depletion and Amortization	(13,115)	(12,716)
Total Property, Plant and Equipment, Net	18,396	18,548
Goodwill	1,295	—
Other Noncurrent Assets	416	508
Total Assets	\$ 21,649	\$ 21,011
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable - Trade	\$ 1,123	\$ 736
Other Current Liabilities	499	742
Total Current Liabilities	1,622	1,478
Long-Term Debt	7,487	7,011
Deferred Income Taxes	1,352	1,819
Other Noncurrent Liabilities	1,245	1,103
Total Liabilities	11,706	11,411
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; 529 Million and 471 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,415	6,450
Accumulated Other Comprehensive Loss	(29)	(31)
Treasury Stock, at Cost; 39 Million and 38 Million Shares, respectively	(728)	(692)
Retained Earnings	1,803	3,556
Noble Energy Share of Equity	9,466	9,288
Noncontrolling Interests	477	312
Total Equity	9,943	9,600
Total Liabilities and Equity	\$ 21,649	\$ 21,011

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

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

	Nine Months Ended September 30,	
	2017	2016
Cash Flows From Operating Activities		
Net Loss Including Noncontrolling Interests	\$ (1,566)	\$ (745)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,554	1,859
Loss on Marcellus Shale Upstream Divestiture	2,326	—
Deferred Income Tax Benefit	(988)	(699)
Dry Hole Cost	2	105
Undeveloped Leasehold Impairment	51	81
Loss (Gain) on Extinguishment of Debt	98	(80)
(Gain) Loss on Commodity Derivative Instruments	(145)	53
Net Cash Received in Settlement of Commodity Derivative Instruments	18	454
Stock Based Compensation	83	61
Other Adjustments for Noncash Items Included in Income	12	136
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	(148)	6
Increase (Decrease) in Accounts Payable	230	(124)
(Decrease) Increase in Current Income Taxes Payable	(41)	82
Other Current Assets and Liabilities, Net	(5)	(72)
Other Operating Assets and Liabilities, Net	(63)	(63)
Net Cash Provided by Operating Activities	1,418	1,054
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,956)	(1,164)
Proceeds from Marcellus Shale Upstream Divestiture	1,028	—
Clayton Williams Energy Acquisition	(616)	—
Other Acquisitions	(327)	—
Additions to Equity Method Investments	(68)	(8)
Proceeds from Divestitures and Other	129	786
Net Cash Used in Investing Activities	(1,810)	(386)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(141)	(129)
Proceeds from Noble Midstream Services Revolving Credit Facility	245	—
Repayment of Noble Midstream Services Revolving Credit Facility	(45)	—
Proceeds from Term Loan Facility	—	1,400
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	138	299
Proceeds from Revolving Credit Facility	1,585	—
Repayment of Revolving Credit Facility	(1,310)	—
Repayment of Clayton Williams Energy Long-term Debt	(595)	—
Proceeds from Issuance of Senior Notes, Net	1,086	—
Repayment of Senior Notes	(1,096)	(1,383)
Other	(91)	(64)
Net Cash (Used in) Provided by Financing Activities	(224)	123
(Decrease) Increase in Cash and Cash Equivalents	(616)	791
Cash and Cash Equivalents at Beginning of Period	1,180	1,028
Cash and Cash Equivalents at End of Period	\$ 564	\$ 1,819

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

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

	Attributable to Noble Energy							Non-controlling Interests	Total Equity
	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings				
December 31, 2016	\$ 5	\$ 6,450	\$ (31)	\$ (692)	\$ 3,556	\$ 312	\$ 9,600		
Net (Loss) Income	—	—	—	—	(1,612)	46	(1,566)		
Clayton Williams Energy Acquisition	—	1,876	—	(25)	—	—	1,851		
Stock-based Compensation	—	80	—	—	—	—	80		
Dividends (30 cents per share)	—	—	—	—	(141)	—	(141)		
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	138	138		
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(19)	(19)		
Other	—	9	2	(11)	—	—	—		
September 30, 2017	\$ 5	\$ 8,415	\$ (29)	\$ (728)	\$ 1,803	\$ 477	\$ 9,943		
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 Partners 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		

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

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

Note 1. Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our historical operating areas include: US onshore, primarily the DJ Basin, Delaware Basin, Eagle Ford Shale and Marcellus Shale (until June 2017); US offshore Gulf of Mexico; Eastern Mediterranean; and West Africa. Our Midstream segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

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, 2017 and December 31, 2016 and for the three and nine months ended September 30, 2017 and 2016 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. For the periods presented, activity within other comprehensive income or loss was de minimis; therefore, net income or loss is materially consistent with comprehensive income or loss.

In [Note 11. Segment Information](#), we report a new Midstream segment, established second quarter 2017, and present prior period amounts on a comparable basis. Certain other prior-period amounts have been reclassified to conform to the current period presentation.

Operating results for the three and nine months ended September 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

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, 2016.

Consolidation Our consolidated financial statements include our accounts, the accounts of subsidiaries which Noble Energy wholly owns, and the accounts of 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 Partners LP (NYSE: NBLX) (Noble Midstream Partners) lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact Noble Midstream Partners' economic performance; therefore, Noble Midstream Partners is considered a VIE. Through Noble Energy's ownership interest in Noble Midstream GP LLC (the General Partner to Noble Midstream Partners), 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 Partners. Therefore, Noble Energy is considered the primary beneficiary and consolidates Noble Midstream Partners.

Goodwill As of September 30, 2017, our consolidated balance sheet includes goodwill of \$1.3 billion. This goodwill resulted from the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) completed on April 24, 2017, and represents the excess of the consideration paid for Clayton Williams Energy over the net amounts assigned to identifiable assets acquired and liabilities assumed. All of our recorded goodwill is assigned to the Texas reporting unit. See [Note 3. Clayton Williams Energy Acquisition](#).

Goodwill is not amortized to earnings but is qualitatively assessed for impairment. We assess goodwill for impairment annually during the third quarter, or more frequently as circumstances require, at the reporting unit level. If, based on our qualitative procedures, it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we perform the two-step goodwill impairment test. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors decline. See Recently Issued Accounting Standards – Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment, below, for newly issued accounting guidance regarding future goodwill impairment testing.

We conducted a qualitative goodwill impairment assessment as of September 30, 2017 by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions as pertinent to current and expected regulations, industry and market conditions, including overall global and regional supply and demand and impact of such on commodity prices; as well as microeconomic factors relevant to the enterprise such as cost factors that have a negative effect on earnings and cash flows, overall financial performance, reporting unit dispositions, acquisitions, portfolio

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

restructuring and other decisions / circumstances specific to the entity and the reporting unit containing goodwill. Certain negative indicators included the current commodity price environment (driven by several macroeconomic factors) coupled with onshore service cost inflation resulting in pressure on operating margins impacting our financial results associated with the Texas reporting unit and our stock price. However, we in turn also noted positive indicators such as our current and future drilling and development plans for our Texas assets, synergies we expect from the Clayton Williams Energy Acquisition driven by our unconventional expertise and position in the adjacent properties which further increase opportunities to drill longer lateral wells on our combined acreage positions, which would contribute to profitability. Furthermore, we see value creation to be derived from expected midstream build-out opportunities for the gathering, processing and servicing of future production in the Delaware basin. Having assessed the totality of such events and circumstances described above, we determined that while there exist certain negative factors, the overall qualitative assessment did not indicate that it is more likely than not that the fair value of the reporting unit is less than its carrying value. However, regardless of the outcome of the qualitative review, we decided to proceed with the conduct of Step 1 of the impairment test as part of our annual review.

As such, we performed Step 1 of the goodwill impairment test, used to identify potential impairment. The result of the Step 1 test indicated that the fair value of the Texas reporting unit exceeded its carrying value, including goodwill, by approximately 6% and therefore, the Texas reporting unit goodwill was not considered to be impaired as of September 30, 2017.

If, in the future, we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we will include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount will be based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained.

Exit Costs We recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. Our exit costs in 2017 relate primarily to estimated costs associated with a retained Marcellus Shale firm transportation contract, for which we accrued an exit liability at June 30, 2017.

The recognition and fair value estimation of a liability requires that management take into account certain estimates and assumptions such as: the determination of whether a cease-use date has occurred (defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services); the amount, if any, of economic benefit that is expected to be obtained from a contract through partial use or release; and our estimate of costs that will continue to be incurred under the contract. We record the liability at estimated fair value, based on expected future cash outflows required to satisfy the obligation, net of estimated recoveries, and discounted. Exit costs, and associated accretion expense, are included in operating expense in our consolidated statements of operations. See [Note 4. Acquisitions and Divestitures](#) and [Note 12. Commitments and Contingencies](#).

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.

Reserves Estimates Estimated quantities of crude oil, natural gas and natural gas liquids (NGL) reserves are the most significant of our estimates. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. The accuracy of any reserves estimate is a function of the quality of available engineering and geoscience information and also interpretation of the provided data. As a result, reserves estimates may be different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered.

During the first nine months of 2017, we recorded the following significant changes in our proved reserves estimates:

- **Leviathan Field** In second quarter 2017, we recorded proved undeveloped reserves of 551 MMBoe, net, for the Leviathan field, offshore Israel, upon approval and sanction of the first phase of development, and are expecting to initiate natural gas production by the end of 2019.
- **Tamar Field** In third quarter 2017, we completed additional reservoir modeling reflecting integration of the Tamar 8 well results into our geologic modeling across the reservoir and, as a result, we added one Tcfe, gross, or 48 MMBoe, net, for the Tamar Field, offshore Israel, of proved developed natural gas reserves as of September 30, 2017.
- **Delaware Basin** We recorded net proved reserves of approximately 86 MMBoe, of which approximately 17 MMBoe are proved developed reserves and 69 MMBoe are proved undeveloped reserves as of June 30, 2017 related to the Clayton Williams Energy Acquisition.

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

- **Marcellus Shale** The Marcellus Shale upstream divestiture resulted in a decrease in net proved reserves of approximately 241 MMBoe as of June 30, 2017, of which approximately 190 MMBoe were proved developed reserves and 51 MMBoe were proved undeveloped reserves.

Recently Issued Accounting Standards

Revenue Recognition 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, revenue recognition would occur upon 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.

We continue to evaluate the impact of the ASU on our accounting policies, internal controls, and consolidated financial statements and related disclosures. We are performing a review of contracts for each of our revenue streams and developing accounting policies to address the provisions of the ASU. Currently, we do not have any contracts that would require a change from the entitlements method, historically used for certain domestic natural gas sales, to the sales method of accounting. The ASU also includes provisions regarding future revenues and expenses under a gross-versus-net presentation. We are evaluating the impact, if any, on the presentation of our future revenues and expenses under this gross-versus-net presentation guidance. Based upon assessments performed to date, we do not expect the ASU to have a material effect on the timing of revenue recognition or our financial position. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. We will adopt the new standard on January 1, 2018, using the modified retrospective approach with a cumulative adjustment to retained earnings as necessary.

Compensation – Stock Compensation (Topic 718): Scope of Modification Accounting In May 2017, the FASB issued Accounting Standards Update No. 2017-09 (ASU 2017-09) *Compensation – Stock Compensation (Topic 718)*. The purpose of this update is to provide clarity as to which modifications of awards require modification accounting under Topic 718, whereas previously issued guidance frequently resulted in varying interpretations and a diversity of practice. An entity should employ modification accounting unless the following are met: (1) the fair value of the award is the same immediately before and after the award is modified; (2) the vesting conditions are the same under both the modified award and the original award; and (3) the classification of the modified award is the same as the original award, either equity or liability. Regardless of whether modification accounting is utilized, award disclosure requirements under Topic 718 remain unchanged. ASU 2017-09 will be effective for annual or any interim periods beginning after December 15, 2017. We do not believe adoption of ASU 2017-09 will have a material impact on our financial statements. We will adopt the new standard on the effective date of January 1, 2018.

Business Combinations: Clarifying the Definition of a Business In January 2017, the FASB issued Accounting Standards Update No. 2017-01 (ASU 2017-01): *Business Combinations – Clarifying the Definition of a Business*, that assists in determining whether certain transactions should be accounted for as acquisitions or dispositions of assets or businesses. The amendment provides a screen to be applied to the fair value of an acquisition or disposal to evaluate whether the assets in question are simply assets or if they meet the requirements of a business. If the screen is not met, no further evaluation is needed. If the screen is met, certain steps are subsequently taken to make the determination. This ASU is designed to reduce the number of transactions to be accounted for as business transactions, which take more time and cost more to analyze than asset transactions. This ASU is effective for annual and interim periods beginning after December 15, 2017 and is required to be applied prospectively. Our current Clayton Williams Energy Acquisition is not impacted by this guidance and we will apply the new guidance to applicable and qualifying transactions after our adoption on January 1, 2018.

Statement of Cash Flows: Restricted Cash In November 2016, the FASB issued Accounting Standards Update No. 2016-18 (ASU 2016-18): *Statement of Cash Flows – Restricted Cash*, which requires amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. This ASU will be effective for annual and interim periods beginning after December 15, 2017, with earlier application permitted. We do not believe adoption of ASU 2016-18 will have a material impact on our statement of cash flows and related disclosures. We will adopt the new standard on the effective date of January 1, 2018.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments 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 eight specific cash receipt and cash payment transactions should be presented in the statement of cash flows. 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. We will adopt the new standard on the effective date of January 1, 2018.

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

Leases 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.

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. At this time, we cannot reasonably estimate the financial impact this ASU will have on our financial statements; however, we believe adoption and implementation of this ASU will have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities. As part of our assessment to date, we have formed an implementation work team, prepared educational and training materials pertinent to this ASU and have begun contract review and documentation. We will adopt the new standard on the effective date of January 1, 2019.

Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04): *Intangibles – Goodwill and Other – Simplifying the Test for Goodwill Impairment*, to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. Under the new guidance, an entity will perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount, with an impairment charge being recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. ASU 2017-04 will be effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the provisions of ASU 2017-04 and have not yet determined if we will early adopt.

Financial Instruments: Credit Losses 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. We will adopt the new standard on the effective date of January 1, 2020.

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

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

<i>(millions)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Production Expense				
Lease Operating Expense	\$ 151	\$ 131	\$ 414	\$ 412
Production and Ad Valorem Taxes	36	30	119	73
Gathering, Transportation and Processing Expense ⁽¹⁾	93	121	333	354
Total	\$ 280	\$ 282	\$ 866	\$ 839
Exploration Expense				
Leasehold Impairment and Amortization ⁽²⁾	\$ 33	\$ 96	\$ 51	\$ 127
Dry Hole Cost ⁽³⁾	2	5	2	105
Seismic, Geological and Geophysical	7	15	20	47
Staff Expense	11	15	40	53
Other	11	(6)	23	44
Total	\$ 64	\$ 125	\$ 136	\$ 376
Loss on Marcellus Shale Upstream Divestiture ⁽⁴⁾				
Loss on Sale	\$ —	\$ —	\$ 2,270	\$ —
Firm Transportation Commitment ⁽⁵⁾	—	—	41	—
Other ⁽⁶⁾	4	—	15	—
Total	\$ 4	\$ —	\$ 2,326	\$ —
Other Operating Expense, Net ⁽⁷⁾				
Marketing Expense ⁽¹⁾⁽⁸⁾	\$ 6	\$ 12	\$ 39	\$ 39
Clayton Williams Energy Acquisition Expenses ⁽⁹⁾	4	—	98	—
Loss on Asset Due to Terminated Contract ⁽¹⁰⁾	—	—	—	47
North Sea Remediation Project Revision ⁽¹¹⁾	(42)	—	(42)	—
Other, Net	17	25	37	41
Total	\$ (15)	\$ 37	\$ 132	\$ 127

⁽¹⁾ Certain of our gathering and processing expenses were historically presented as components of other operating expense, net, in our consolidated statements of operations. Beginning in 2017, we have changed our presentation to reflect these as components of production expense. These costs are now included within gathering, transportation and processing expense. For the three and nine months ended September 30, 2017, these costs totaled \$12 million and \$17 million, respectively. For the three and nine months ended September 30, 2016, these costs totaled \$8 million and \$19 million, respectively, and have been reclassified from marketing expense to conform to the current presentation.

⁽²⁾ See [Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs](#).

⁽³⁾ For the nine months ended September 30, 2016, amount related primarily to the Silvergate exploratory well, Gulf of Mexico, and the Dolphin 1 natural gas discovery, offshore Israel.

⁽⁴⁾ See [Note 4. Acquisitions and Divestitures](#).

⁽⁵⁾ Amount represents expense related to an unutilized firm transportation commitment associated with a Marcellus Shale firm transportation contract. See [Note 12. Commitments and Contingencies](#).

⁽⁶⁾ Amount includes costs for legal and advisory services and employee severance charges.

⁽⁷⁾ (Gain)/Loss on debt extinguishment was historically presented as a component of other operating expense, net in our consolidated statements of operations. Beginning with third quarter 2017, we have changed our presentation to reflect these as a separate line item within other expense (income) below operating loss. The prior periods have been reclassified to conform to that presentation.

⁽⁸⁾ Amounts represent expense for unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.

⁽⁹⁾ See [Note 3. Clayton Williams Energy Acquisition](#).

⁽¹⁰⁾ Amounts relate to the termination and final settlement of a rig contract for offshore Falkland Islands as a result of a supplier's non-performance.

⁽¹¹⁾ See [Note 9. Asset Retirement Obligations](#).

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

Balance Sheet Information Other balance sheet information is as follows:

<i>(millions)</i>	September 30, 2017	December 31, 2016
Accounts Receivable, Net		
Commodity Sales	\$ 403	\$ 403
Joint Interest Billings	183	106
Proceeds Receivable ⁽¹⁾	—	40
Other	106	86
Allowance for Doubtful Accounts	(17)	(20)
Total	\$ 675	\$ 615
Other Current Assets		
Inventories, Materials and Supplies	\$ 61	\$ 71
Inventories, Crude Oil	17	18
Assets Held for Sale ⁽²⁾	180	18
Restricted Cash ⁽³⁾	—	30
Prepaid Expenses and Other Current Assets	45	23
Total	\$ 303	\$ 160
Other Noncurrent Assets		
Equity Method Investments	\$ 286	\$ 400
Mutual Fund Investments	70	71
Other Assets, Noncurrent	60	37
Total	\$ 416	\$ 508
Other Current Liabilities		
Production and Ad Valorem Taxes	\$ 118	\$ 115
Commodity Derivative Liabilities	4	102
Income Taxes Payable	13	53
Asset Retirement Obligations ⁽⁴⁾	50	160
Interest Payable	82	76
Current Portion of Capital Lease Obligations	65	63
Foreign Sales Tax Payable	29	14
Compensation and Benefits Payable	87	110
Theoretical Withdrawal Premium	25	18
Other Liabilities, Current ⁽⁵⁾	26	31
Total	\$ 499	\$ 742
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	\$ 216	\$ 218
Asset Retirement Obligations ⁽⁴⁾	894	775
Marcellus Shale Firm Transportation Commitment ⁽⁶⁾	31	—
Production and Ad Valorem Taxes	49	47
Other Liabilities, Noncurrent	55	63
Total	\$ 1,245	\$ 1,103

⁽¹⁾ Balance at December 31, 2016 related to the farm-out of a 35% interest in Block 12 offshore Cyprus; proceeds were received in January 2017. See [Note 4. Acquisitions and Divestitures](#).

⁽²⁾ Balance at September 30, 2017 primarily includes our equity investment in CONE Gathering, LLC. See [Note 4. Acquisitions and Divestitures](#).

⁽³⁾ Balance at December 31, 2016 represented amount held in escrow for the purchase of certain Delaware Basin properties. The transaction closed in first quarter 2017. See [Note 4. Acquisitions and Divestitures](#).

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

- (4) Reclassification from current to noncurrent is driven primarily by a change in expected timing of abandonment activities in the Gulf of Mexico. See [Note 9. Asset Retirement Obligations](#).
- (5) Balance at September 30, 2017 includes \$8 million associated with the current portion of the Marcellus Shale firm transportation commitment. See [Note 12. Commitments and Contingencies](#).
- (6) See [Note 12. Commitments and Contingencies](#).

Note 3. Clayton Williams Energy Acquisition

In January 2017, we announced the Clayton Williams Energy Acquisition, which was approved by Clayton Williams Energy stockholders and closed on April 24, 2017. Acquired assets include 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings in Texas, and an additional 100,000 net acres in other areas of the Permian and Midland Basins. In total, the acquisition increased our Delaware Basin position to approximately 118,000 net acres.

We recorded net proved reserves of approximately 86 MMBoe, of which approximately 17 MMBoe are proved developed reserves and 69 MMBoe are proved undeveloped reserves, as of June 30, 2017. In addition, upon closing of the acquisition, approximately 64,000 net acres in Reeves County, Texas were dedicated to Noble Midstream Partners for infield crude oil, natural gas and produced water gathering.

The acquisition was effected through the issuance of approximately 56 million shares of Noble Energy common stock with a fair value of approximately \$1.9 billion and cash consideration of \$637 million, for total consideration of approximately \$2.5 billion, in exchange for all outstanding Clayton Williams Energy shares, including stock options, restricted stock awards and warrants. The closing price of our stock on the New York Stock Exchange (NYSE) was \$34.17 on April 24, 2017. In connection with the transaction, we borrowed \$1.3 billion under our Revolving Credit Facility (defined below) to fund the cash portion of the acquisition consideration, redeem outstanding Clayton Williams Energy debt, pay associated make-whole premiums and pay related fees and expenses. See [Note 6. Debt](#).

In connection with the Clayton Williams Energy Acquisition, we have incurred acquisition-related costs of \$98 million to date, including \$64 million of severance, consulting, investment, advisory, legal and other merger-related fees, and \$34 million of noncash share-based compensation expense, all of which were expensed and are included in other operating expense, net in our consolidated statements of operations. In addition, we received approximately 720,000 shares of common stock from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of their restricted shares and options pursuant to the purchase and sale agreement, resulting in a \$25 million increase in our treasury stock balance.

Purchase Price Allocation The transaction has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Clayton Williams Energy to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Any value assigned to goodwill is not expected to be deductible for income tax purposes.

Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-merger contingencies, final tax returns that provide the underlying tax basis of Clayton Williams Energy's assets and liabilities, and final appraisals of assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities, including any goodwill, may be revised as appropriate.

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

The following table sets forth our preliminary purchase price allocation:

(millions, except per share amounts)

Fair Value of Common Stock Issued	\$	1,876
Plus: Cash Consideration Paid to Clayton Williams Energy Stockholders		637
Total Purchase Price	\$	2,513
Plus Liabilities Assumed by Noble Energy:		
Accounts Payable		67
Other Current Liabilities		38
Long-Term Deferred Tax Liability		520
Long-Term Debt		595
Asset Retirement Obligations		58
Total Purchase Price Plus Liabilities Assumed	\$	3,791

The fair value of Clayton Williams Energy's identifiable assets is as follows:

(millions)

Cash and Cash Equivalents	\$	21
Other Current Assets		63
Oil and Gas Properties:		
Proved Reserves		722
Undeveloped Leasehold Cost		1,571
Gathering and Processing Assets		48
Asset Retirement Costs		58
Other Noncurrent Assets		13
Implied Goodwill		1,295
Total Asset Value	\$	3,791

In connection with the acquisition, we assumed, and then subsequently retired, \$595 million of Clayton Williams Energy long-term debt. The fair value measurements of long-term debt were estimated based on the early redemption 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 expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved, possible and probable reserves; (ii) production rates and related development timing; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by management at the time of the valuation and are the most sensitive and may be subject to change.

Based upon the preliminary purchase price allocation, we have recognized \$1.3 billion of goodwill, all of which is assigned to the Texas reporting unit. As a result of the acquisition, we expect to realize certain synergies which may result from our control of the combined assets as well as future midstream opportunities. The oil-rich geology of these assets, coupled with our unconventional expertise and position in the adjacent properties, significantly enhances our crude oil focus and growth outlook. The acquisition provides for synergies related to administrative and capital efficiencies, and increased opportunities to drill longer lateral wells on our combined acreage positions, enhances our crude oil production base and future crude oil growth potential. It also adds to our midstream assets and provides future midstream build-out opportunities for the gathering, processing and servicing of future production in the basin.

The results of operations attributable to Clayton Williams Energy are included in our consolidated statements of operations beginning on April 24, 2017. We generated revenues of \$56 million and a pre-tax loss of \$14 million from the Clayton Williams Energy assets during the period April 24, 2017 to September 30, 2017.

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

Pro Forma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Clayton Williams Energy and gives effect to the acquisition as if it had occurred on January 1, 2016. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) Noble Energy's common stock and equity awards issued to convert Clayton Williams Energy's outstanding shares of common stock and equity awards and conversion of warrants as of the closing date of the acquisition, (ii) depletion of Clayton Williams Energy's fair-valued proved crude oil and natural gas properties, and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings for the three and nine months ended September 30, 2017 were adjusted to exclude acquisition-related costs of \$4 million and \$98 million, respectively, incurred by Noble Energy and \$23 million, incurred by Clayton Williams Energy in second quarter 2017. The pro forma results of operations do not include any cost savings or other synergies that we expect to realize from the Clayton Williams Energy Acquisition or any estimated costs that have been or will be incurred by us to integrate the Clayton Williams Energy 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 Clayton Williams Energy Acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

<i>(millions, except per share amounts)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017 ⁽¹⁾	2016	2017	2016
Revenues	\$ 960	\$ 964	\$ 3,102	\$ 2,605
Net Loss and Comprehensive Loss Attributable to Noble Energy	(133)	(193)	(1,561)	(860)
Net Loss Attributable to Noble Energy per Common Share				
Basic and Diluted	\$ (0.27)	\$ (0.40)	\$ (3.21)	\$ (1.77)

⁽¹⁾ Adjusted for \$4 million acquisition-related costs, net of 35% tax, incurred during third quarter 2017.

Note 4. Acquisitions and Divestitures

2017 Asset Transactions

During the first nine months of 2017, we engaged in the following asset transactions.

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of all of our Marcellus Shale upstream assets, which are primarily natural gas properties. The sales price totaled \$1.2 billion, and we received \$1.0 billion of net cash proceeds, after consideration of customary adjustments, at closing. The sales price includes additional contingent consideration of up to \$100 million structured as three separate payments of \$33.3 million each. The contingent payments are in effect should the average annual price of the Appalachia Dominion, South Point index exceed \$3.30 per MMBtu in the individual annual periods from 2018 through 2020. To date, conditions for the recognition of the contingent consideration are not probable and therefore, no amounts have been accrued related to the contingent consideration. Proceeds from the transaction were used to repay borrowings resulting from the Clayton Williams Energy Acquisition. See [Note 6. Debt](#).

In second quarter 2017, we recognized a total loss of \$2.3 billion, or \$1.5 billion after-tax, on this transaction. The aggregate net book value of the properties prior to the sale was approximately \$3.4 billion, which included approximately \$883 million of undeveloped leasehold cost.

As part of the total loss, we recorded a charge of \$41 million, discounted, relating to a retained transportation contract where the pipeline project is currently in service. We no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. As such, we recorded a charge in accordance with accounting for exit or disposal activities under ASC 420 - Exit or Disposal Cost Obligations. In addition, we have retained other Marcellus Shale firm transportation contracts, relating to pipeline projects which are not yet commercially available to us. These projects are either under construction or have not yet been approved by the Federal Energy Regulatory Commission (FERC). As these projects become commercially available to us, we will assess, based upon the facts and circumstances, the recognition of any potential exit cost liabilities. It is likely we will incur additional firm transportation, as well as other restructuring or office closure costs, associated with this exit activity in the future. See [Note 2. Basis of Presentation](#) and [Note 12. Commitments and Contingencies](#).

For the nine months ended September 30, 2017, our consolidated statements of operations include a pre-tax loss of \$2.3 billion associated with the divested Marcellus Shale upstream assets, driven by the loss on sale. For the three and nine months ended September 30, 2016, our consolidated statements of operations include a pre-tax loss of \$70 million and \$237 million, respectively, associated with the divested Marcellus Shale upstream assets.

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

Production from the Marcellus Shale upstream assets averaged 393 MMcfe/d and 413 MMcfe/d for the three and six months ended June 30, 2017. With the closing of the sale, we recorded a decrease in net proved reserves of approximately 241 MMBoe, of which approximately 190 MMBoe were proved developed reserves and 51 MMBoe were proved undeveloped reserves as of June 30, 2017.

Marcellus Shale CONE Gathering Divestiture On May 18, 2017, we announced the signing of a definitive agreement to divest an affiliate that holds the 50% interest in CONE Gathering, LLC (CONE Gathering) and 21.7 million common and subordinated limited partnership units in CONE Midstream Partners LP (NYSE:CNNX) (CONE Midstream), for total cash consideration of \$765 million. CONE Gathering owns the general partner of CONE Midstream, and the limited partnership units represent a 33.5% ownership interest in CONE Midstream. CONE Midstream constructs, owns and operates natural gas gathering and other midstream energy assets in support of Marcellus Shale activities.

In connection with the execution of the definitive agreement to divest the affiliate noted above, the other 50% owner of CONE Gathering filed suit to enjoin the transaction. A bench trial was concluded on October 20, 2017 and we are awaiting a decision from the court. We believe that the court will decide in our favor. However, given the pendency of the matter and the possibility of appeal, our ability to close the transaction as originally contemplated is uncertain at this time.

We are committed to exiting the Marcellus Shale play, and going forward, our midstream efforts are primarily focused on Noble Midstream Partners, supporting our DJ Basin and Delaware Basin growth areas. We believe that classification of our investment in CONE Gathering as assets held for sale as of September 30, 2017 remains appropriate.

Assets Held for Sale At September 30, 2017, assets held for sale was primarily related to \$173 million for our investment in CONE Gathering.

Other US Onshore Properties We conducted the following transactions:

- **Onshore US Divestitures** In third quarter 2017, we received proceeds of \$24 million resulting from the sale of certain other onshore US properties and the remaining consideration associated with the Greeley Crescent divestiture (defined below) in the DJ Basin.
- **Delaware Basin Acquisition** In first quarter 2017, we closed a bolt-on acquisition in the Delaware Basin for \$301 million, approximately \$246 million of which was allocated to undeveloped leasehold cost. The acquisition included seven producing wells, of which four are operated by us.

Noble Midstream Partners

Asset Contribution On June 26, 2017, Noble Midstream Partners acquired an additional 15% limited partner interest in Blanco River DevCo LP (Blanco River DevCo), increasing its ownership to 40% of the Blanco River DevCo LP, and acquired the remaining 20% limited partner interest in Colorado River DevCo LP (Colorado River DevCo) from us for \$270 million.

Blanco River DevCo holds Noble Midstream Partners' Delaware Basin in-field gathering dedications for crude oil and produced water gathering services on approximately 111,000 net acres, with substantially all of the acreage also dedicated for natural gas gathering. Colorado River DevCo provides services across our development areas in the DJ Basin, including crude oil and natural gas gathering and water services in the Wells Ranch area and crude oil gathering in the East Pony area.

The \$270 million consideration consisted of \$245 million in cash and 562,430 common units representing limited partner interests in Noble Midstream Partners. Noble Midstream Partners funded the cash consideration with approximately \$138 million of net proceeds from a concurrent private placement of common units and \$90 million of borrowings under the Noble Midstream Services Revolving Credit Facility (defined below) and the remainder from cash on hand.

Advantage Acquisition On April 3, 2017, Noble Midstream Partners and Plains Pipeline, L.P., a wholly owned subsidiary of Plains All American Pipeline, L.P., acquired Advantage Pipeline, L.L.C. (Advantage Pipeline) for \$133 million through a newly formed 50/50 joint venture (Advantage Joint Venture). Noble Midstream Partners contributed \$67 million of cash to the joint venture, funded by available cash on hand and the Noble Midstream Services Revolving Credit Facility. The Advantage Joint Venture is accounted for under the equity method and is included within our Midstream segment.

Noble Midstream Partners serves as the operator of the Advantage Pipeline system, which includes a 70-mile crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150,000 barrels per day of shipping capacity (expandable to over 200,000 barrels per day) and 490,000 barrels of storage capacity.

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

2016 Asset Transactions

During the first nine months of 2016, we engaged in the following asset transactions.

US Onshore Properties We entered into the following transactions:

- *Bowdoin Divestiture* We closed the divestiture of our Bowdoin property in northern Montana, generating proceeds of \$43 million, and recognized a \$23 million loss on sale;
- *Onshore US Divestitures* We sold certain other US onshore properties, generating net proceeds of \$20 million, which were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss;
- *Greeley Crescent Divestiture* We entered into a purchase and sale agreement for the divestiture of certain producing and undeveloped interests covering approximately 33,100 net acres in the Greeley Crescent (Greeley Crescent divestiture) area of the DJ Basin for \$505 million, subject to customary closing adjustments. We received proceeds of \$486 million during second quarter 2016, which were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss. In third quarter 2017, we closed the sale of the remaining properties and received proceeds of \$5 million; and
- *Acreage Exchange Agreement* We entered into an acreage exchange agreement receiving approximately 11,700 net acres within our Wells Ranch development area in exchange for approximately 13,500 net acres primarily from our Bronco area, located southwest of Wells Ranch, with no recognition of gain or loss.

Cyprus Project (Offshore Cyprus) In first quarter 2017, we received the remaining \$40 million consideration for the farm-out of a 35% interest in Block 12, which includes the Aphrodite natural gas discovery. Proceeds received, including \$131 million in first quarter 2016, were applied to the Cyprus project asset with no gain or loss recognized.

Offshore Israel Assets In first quarter 2016, we closed the divestment of our 47% interest in the Alon A and Alon C licenses, which include the Karish and Tanin fields, for a total sales price of \$73 million (\$67 million for asset consideration and \$6 million for cost adjustments). Proceeds were applied to reduce field basis with no recognition of gain or loss.

Note 5. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil, natural gas and NGL 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 7. Fair Value Measurements and Disclosures](#) for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

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

Unsettled Commodity Derivative Instruments As of September 30, 2017, the following crude oil derivative contracts were outstanding:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps		Collars		
				Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2H17 ⁽¹⁾	Call Option ⁽²⁾	NYMEX WTI	3,000	\$ —	\$ —	\$ —	\$ —	\$ 60.12
2H17 ⁽¹⁾	Three-Way Collars	ICE Brent	5,000	—	—	43.00	50.00	64.00
2017	Three-Way Collars	NYMEX WTI	24,000	—	—	39.08	47.71	61.20
2017	Two-Way Collars	NYMEX WTI	10,804	—	—	—	40.80	52.72
2017	Swaps	NYMEX WTI	4,293	—	50.84	—	—	—
2017	Call Option ⁽²⁾	NYMEX WTI	3,000	—	—	—	—	57.00
2017	Three-Way Collars	ICE Brent	2,000	—	—	43.00	50.00	63.15
2017	Three-Way Collars	Dated Brent	2,000	—	—	35.00	45.00	66.33
2018	Three-Way Collars	NYMEX WTI	10,000	—	—	45.50	52.50	69.09
2018	Three-Way Collars	Dated Brent	3,000	—	—	40.00	50.00	70.41
2018	Swaptions ⁽³⁾	NYMEX WTI	3,000	—	56.10	—	—	—
2018	Three-Way Collars	ICE Brent	5,000	—	—	43.00	50.00	59.50
2018	Two-Way Collars	ICE Brent	2,000	—	—	—	50.00	55.25
2018	Basis Swap	⁽⁴⁾	8,000	(0.78)	—	—	—	—
2019	Three-Way Collars	ICE Brent	3,000	—	—	43.00	50.00	64.07
2019	Basis Swap	⁽⁴⁾	12,000	(1.01)	—	—	—	—

⁽¹⁾ We have entered into contracts for portions of 2017 resulting in the difference in hedged volumes for the full year.

⁽²⁾ 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.

⁽³⁾ We have entered into certain derivative contracts (swaptions), which give counterparties the right, but not the obligation, to enter into swap agreements with us on the option expiration dates.

⁽⁴⁾ We have entered into crude oil basis swap contracts in order to fix the differential between pricing in Midland, Texas, and Cushing, Oklahoma. The weighted average differential represents the amount of reduction to Cushing, Oklahoma, prices for the notional volumes covered by the basis swap contracts.

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

As of September 30, 2017, the following natural gas derivative contracts were outstanding:

Settlement Period	Type of Contract	Index	MMBtu Per Day	Swaps		Collars	
				Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2017	Three-Way Collars	NYMEX HH	110,000	\$ —	\$ 2.58	\$ 2.93	\$ 3.65
2017	Two-Way Collars	NYMEX HH	70,000	—	—	2.93	3.32
2018	Three-Way Collars	NYMEX HH	120,000	—	2.50	2.88	3.65
2018	Swaptions ⁽¹⁾	NYMEX HH	30,000	3.36	—	—	—

⁽¹⁾ We have entered into certain derivative contracts (swaptions), which give counterparties the right, but not the obligation, to enter into swap agreements with us on the option expiration dates.

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

	Fair Value of Derivative Instruments							
	Asset Derivative Instruments				Liability Derivative Instruments			
	September 30, 2017		December 31, 2016		September 30, 2017		December 31, 2016	
<i>(millions)</i>	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	\$ 7	Current Assets	\$ —	Current Liabilities	\$ 4	Current Liabilities	\$ 102
	Noncurrent Assets	5	Noncurrent Assets	—	Noncurrent Liabilities	2	Noncurrent Liabilities	14
Total		\$ 12		\$ —		\$ 6		\$ 116

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

<i>(millions)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Cash (Received) Paid in Settlement of Commodity Derivative Instruments				
Crude Oil	\$ (4)	\$ (119)	\$ (20)	\$ (395)
Natural Gas	—	(13)	2	(59)
Total Cash Received in Settlement of Commodity Derivative Instruments	(4)	(132)	(18)	(454)
Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	27	80	(64)	441
Natural Gas	(1)	(3)	(63)	66
Total Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments	26	77	(127)	507
Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	23	(39)	(84)	46
Natural Gas	(1)	(16)	(61)	7
Total Loss (Gain) on Commodity Derivative Instruments	\$ 22	\$ (55)	\$ (145)	\$ 53

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

Note 6. Debt

Debt consists of the following:

<i>(millions, except percentages)</i>	September 30, 2017		December 31, 2016	
	Debt	Interest Rate	Debt	Interest Rate
Revolving Credit Facility, due August 27, 2020	\$ 275	2.27%	\$ —	—%
Noble Midstream Services Revolving Credit Facility, due September 20, 2021	200	2.45%	—	—%
Term Loan Facility, due January 6, 2019	550	2.45%	550	2.01%
Leviathan Term Loan Facility, due February 23, 2025	—	—%	—	—%
Senior Notes, due March 1, 2019 ⁽¹⁾	—	—%	1,000	8.25%
Senior Notes, due May 1, 2021	379	5.625%	379	5.625%
Senior Notes, due December 15, 2021	1,000	4.15%	1,000	4.15%
Senior Notes, due October 15, 2023	100	7.25%	100	7.25%
Senior Notes, due November 15, 2024	650	3.90%	650	3.90%
Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
Senior Notes, due January 15, 2028 ⁽¹⁾	600	3.85%	—	—%
Senior Notes, due March 1, 2041	850	6.00%	850	6.00%
Senior Notes, due November 15, 2043	1,000	5.25%	1,000	5.25%
Senior Notes, due November 15, 2044	850	5.05%	850	5.05%
Senior Notes, due August 15, 2047 ⁽¹⁾	500	4.95%	—	—%
Other Senior Notes and Debentures ⁽²⁾	110	6.93%	110	6.93%
Capital Lease and Other Obligations ⁽³⁾	290	—%	375	—%
Total	7,604		7,114	
Unamortized Discount	(25)		(23)	
Unamortized Premium	14		17	
Unamortized Debt Issuance Costs	(41)		(34)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	7,552		7,074	
Less Amounts Due Within One Year				
Capital Lease Obligations	(65)		(63)	
Long-Term Debt Due After One Year	\$ 7,487		\$ 7,011	

⁽¹⁾ In third quarter 2017, we redeemed all our Senior Notes due March 1, 2019 and issued Senior Notes due January 15, 2028 and August 15, 2047.

⁽²⁾ Includes \$18 million of Senior Notes due June 1, 2022, \$8 million of Senior Notes due June 1, 2024 and \$84 million of Senior Debentures due August 1, 2097. The weighted average interest rate for these instruments is 6.93%.

⁽³⁾ The reduction includes \$41 million related to other obligations for drilling commitments assumed by the acquirer of the Marcellus Shale upstream assets and \$44 million of capital lease principal payments. See [Note 4. Acquisitions and Divestitures](#) and [Note 12. Commitments and Contingencies](#).

Revolving Credit Facility Our Credit Agreement, as amended, provides for a \$4 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.

During second quarter 2017, we borrowed \$1.3 billion to fund the cash portion of the Clayton Williams Energy Acquisition consideration, redeem assumed Clayton Williams Energy long-term debt, pay associated make-whole premiums, pay related fees and expenses associated with the transaction and to fund other general corporate expenditures. We repaid all of the respective outstanding borrowings associated with the transaction during second quarter 2017 with proceeds received from the Marcellus Shale upstream divestiture, cash on hand, and cash generated by the Noble Midstream Partners private placement of limited partner units and Noble Midstream Services borrowings. As of September 30, 2017, \$275 million was outstanding under our Revolving Credit Facility, which was utilized for general corporate purposes and for funding of our capital development program.

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

Noble Midstream Services Revolving Credit Facility In 2016, Noble Midstream Services, LLC, a subsidiary of Noble Midstream Partners, entered into a credit agreement for a \$350 million revolving credit facility (Noble Midstream Services Revolving Credit Facility) which is available to fund working capital and to finance acquisitions and other capital expenditures of Noble Midstream Partners.

Borrowings by Noble Midstream Partners under the Noble Midstream Services Revolving Credit Facility bear interest at a rate equal to an applicable margin plus, at Noble Midstream Partners' option, either (a) 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 (b) in the case of LIBOR borrowings, the offered rate per annum for deposits of dollars for the applicable interest period.

As of September 30, 2017, \$200 million was outstanding under the Noble Midstream Services Revolving Credit Facility which was used to partially fund second quarter 2017 acquisitions. See [Note 4. Acquisitions and Divestitures](#).

Senior Notes Issuance and Completed Tender Offer On August 15, 2017, we issued \$600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and \$500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. Interest on the 3.85% senior notes and 4.95% senior notes is payable semi-annually beginning January 15, 2018 and February 15, 2018, respectively. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. The senior notes were issued at a discount of \$4 million and debt issuance costs incurred totaled \$11 million, both of which are reflected as a reduction of long-term debt and are amortized over the life of the facility. Proceeds of \$1.1 billion from the issuance of senior notes were used solely to fund the tender offer and the redemption of \$1.0 billion of our 8.25% senior notes due March 1, 2019. As a result, we paid a premium of \$96 million to the holders of the 8.25% senior notes and recognized a loss of \$98 million in third quarter 2017, which is reflected in other non-operating (income) expense in our consolidated statements of operations.

Leviathan Term Loan Agreement On February 24, 2017, Noble Energy Mediterranean Ltd. (NEML), a wholly owned subsidiary of Noble Energy, entered into a facility agreement (Leviathan Term Loan Facility) which provides for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to \$1.0 billion, of which \$625 million is initially committed. Any amounts borrowed under the Leviathan Term Loan Facility will be available to fund a portion of our share of costs for the initial phase of development of the Leviathan field offshore Israel.

Any amounts borrowed will be subject to repayment on a quarterly basis following production startup for the first phase of development which is targeted for the end of 2019. Repayment will be in accordance with an amortization schedule set forth in the facility agreement, with a final balloon payment of no more than 35% of the loans outstanding. The Leviathan Term Loan Facility matures on February 23, 2025 and we can prepay borrowings at any time, in whole or in part, without penalty. The Leviathan Term Loan Facility contains customary representations and warranties, affirmative and negative covenants, events of default and also includes a prepayment mechanism that reduces the final balloon amount if cash flows exceed certain defined coverage ratios.

Any amounts borrowed will accrue interest at LIBOR, plus a margin of 3.50% per annum prior to production startup, 3.25% during the period following production startup until the last two years of maturity, and 3.75% during the last two years until the maturity date. We are also required to pay a commitment fee equal to 1.00% per annum on the unused and available commitments under the Leviathan Term Loan Facility until the beginning of the repayment period.

The Leviathan Term Loan Facility is secured by a first priority security interest in substantially all of NEML's interests in the Leviathan field and its marketing subsidiary, and in assets related to the initial phase of the project. All of NEML's revenues from the first phase of Leviathan development will be deposited in collateral accounts and we will be required to maintain a debt service reserve account for the benefit of the lenders under the Leviathan Term Loan Facility. Once servicing accounts are replenished and debt service made, all remaining cash will be available to us and our subsidiaries.

Term Loan Agreement and Completed Tender Offers In 2016, we entered into a term loan agreement (Term Loan Facility) which provides for a three-year term loan facility for a principal amount of \$1.4 billion. The Term Loan Facility accrues 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) LIBOR plus 1.0%, plus a margin that ranges from 10 basis points to 75 basis points depending upon our credit rating, or (b) LIBOR plus a margin that ranges from 100 basis points to 175 basis points depending upon our credit rating.

Borrowings under the Term Loan Facility were used solely to fund tender offers for approximately \$1.38 billion of notes assumed in our merger with Rosetta Resources Inc. in 2015. As a result, we recognized a gain of \$80 million in first quarter 2016 which is reflected in other non-operating (income) expense in our consolidated statements of operations. In fourth quarter 2016, we prepaid \$850 million of long-term debt outstanding under the Term Loan Facility from cash on hand. As of September 30, 2017, \$550 million was outstanding under the facility.

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

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

Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments and outstanding balances under the revolving credit facilities, are as follows:

<i>(millions)</i>	Debt Principal Payments
October - December 2017	\$ —
2018	—
2019	550
2020	—
2021	1,379
Thereafter	4,910
Total	\$ 6,839

Note 7. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

Mutual Fund Investments Our mutual fund investments 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, enhanced swaps and basis 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 5. Derivative Instruments and Hedging Activities](#).

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

Stock-Based Compensation Liability A portion of the value of the liability associated with our phantom unit plan is dependent upon the fair value of Noble Energy common stock as of the end of each reporting period.

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

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

	Fair Value Measurements Using				Fair Value Measurement
	Quoted Prices in Active Markets (Level 1) ⁽¹⁾	Significant Other Observable Inputs (Level 2) ⁽²⁾	Significant Unobservable Inputs (Level 3) ⁽³⁾	Adjustment ⁽⁴⁾	
<i>(millions)</i>					
September 30, 2017					
Financial Assets					
Mutual Fund Investments	\$ 70	\$ —	\$ —	\$ —	\$ 70
Commodity Derivative Instruments	—	16	—	(4)	12
Financial Liabilities					
Commodity Derivative Instruments	—	(10)	—	4	(6)
Portion of Deferred Compensation Liability Measured at Fair Value	(89)	—	—	—	(89)
Stock Based Compensation Liability Measured at Fair Value	(11)	—	—	—	(11)
December 31, 2016					
Financial Assets					
Mutual Fund Investments	\$ 71	\$ —	\$ —	\$ —	\$ 71
Commodity Derivative Instruments	—	5	—	(5)	—
Financial Liabilities					
Commodity Derivative Instruments	—	(121)	—	5	(116)
Portion of Deferred Compensation Liability Measured at Fair Value	(88)	—	—	—	(88)
Stock Based Compensation Liability Measured at Fair Value	(9)	—	—	—	(9)

⁽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 such as inventory, oil and gas properties and assets held for sale are measured at fair value on a nonrecurring basis in our consolidated balance sheets. For the nine months ended September 30, 2017 and 2016, we had no adjustments in fair value related to these items. Other items measured at fair value on a nonrecurring basis are discussed below.

Marcellus Shale Firm Transportation Liability As of September 30, 2017, we had a \$39 million liability representing the discounted present value of our remaining obligation under a firm transportation contract. See [Note 12. Commitments and Contingencies](#).

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 and Revolving Credit Facility, along with the Noble Midstream Services Revolving Credit Facility, are variable-rate, non-public debt. The fair value is estimated based on significant other observable inputs. As such, we consider the fair value of these facilities to be a Level 2 measurement on the fair value hierarchy. See [Note 6. Debt](#).

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

Fair value information regarding our debt is as follows:

<i>(millions)</i>	September 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net ⁽¹⁾	\$ 7,314	\$ 7,715	\$ 6,739	\$ 7,112

⁽¹⁾ Excludes unamortized discount, premium, debt issuance costs and capital lease obligations.

Note 8. 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:

<i>(millions)</i>	Nine Months Ended September 30, 2017
Capitalized Exploratory Well Costs, December 31, 2016	\$ 768
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	10
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves ⁽¹⁾	(203)
Capitalized Exploratory Well Costs, September 30, 2017	\$ 575

⁽¹⁾ Amount relates to the approval and sanction of the first phase of development of the Leviathan field, offshore Israel. During second quarter 2017, we recorded Leviathan field proved undeveloped reserves of 551 MMBoe, net.

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced:

<i>(millions)</i>	September 30, 2017	December 31, 2016
Exploratory Well Costs Capitalized for a Period of One Year or Less	\$ 11	\$ 69
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling ⁽¹⁾	564	699
Balance at September 30, 2017	\$ 575	\$ 768

⁽¹⁾ The decrease from December 31, 2016 is attributable to the reclassification of the Leviathan field to development work in process, partially offset by the capitalization of interest during the period on remaining exploratory wells.

Undeveloped Leasehold Costs We reclassify undeveloped leasehold costs to proved property costs when proved reserves, including proved undeveloped reserves, become attributable to the property as a result of our exploration and development activities. On the other hand, if, based upon a change in exploration plans, timing and extent of development activities, 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 impairment expense related to the respective leases or licenses.

As of September 30, 2017, we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of \$3 billion, including \$1.6 billion related to Delaware Basin assets acquired in the Clayton Williams Energy Acquisition in 2017, and \$1.1 billion and \$149 million attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition in 2015. Undeveloped leasehold costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and are subject to impairment testing.

The remaining balance of undeveloped leasehold costs as of September 30, 2017 included \$56 million related to Gulf of Mexico unproved properties and \$53 million related to international unproved properties. These costs pertain to acquired leases or licenses that are subject to expiration over the next several years unless production is established on units containing the acreage. These costs are evaluated as part of our periodic impairment review. During the first nine months of 2017, we completed geological evaluations of certain Gulf of Mexico leases and licenses associated with other international unproved properties and determined that several should be relinquished or exited. As a result, we recognized \$33 million and \$51 million of undeveloped leasehold impairment expense for the three and nine months ended September 30, 2017, respectively. Of these amounts, \$31 million and \$49 million for the respective periods are attributable to our Gulf of Mexico leases. These expenses are recorded in exploration expense in the consolidated statements of operations.

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

Note 9. 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:

<i>(millions)</i>	Nine Months Ended September 30,	
	2017	2016
Asset Retirement Obligations, Beginning Balance	\$ 935	\$ 989
Liabilities Incurred	83	5
Liabilities Settled	(53)	(87)
Revision of Estimate	(56)	4
Accretion Expense ⁽¹⁾	35	37
Asset Retirement Obligations, Ending Balance	\$ 944	\$ 948

⁽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, 2017 Liabilities incurred include \$58 million related to the Clayton Williams Energy Acquisition and \$25 million primarily for other US onshore wells and facilities placed into service. Liabilities settled include \$37 million related to abandonment of onshore US properties, \$12 million related to properties sold in the Marcellus Shale upstream divestiture and \$4 million related to other offshore international and US properties. Revisions of estimates relate to decreases in cost and timing estimates of \$42 million associated with the North Sea abandonment project and \$29 million for US onshore and Gulf of Mexico, partially offset by an increase of \$15 million for West Africa.

For the Nine Months Ended September 30, 2016 Liabilities incurred were due to new wells and facilities for onshore US. Liabilities settled primarily related to Gulf of Mexico and onshore US property abandonments.

Note 10. Income Taxes

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

<i>(millions)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Current ⁽¹⁾	\$ 22	\$ 148	\$ 71	\$ 213
Deferred	(115)	(285)	(988)	(699)
Total Income Tax Benefit	\$ (93)	\$ (137)	\$ (917)	\$ (486)
Effective Tax Rate	44.7%	48.9%	36.9%	39.5%

⁽¹⁾ Current income taxes are attributable to our operations in Israel and Equatorial Guinea.

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, 2017 varied as compared with the three and nine months ended September 30, 2016 primarily due to a smaller prior year increase to the deferred tax liability recorded on unrepatriated earnings combined with a larger prior year discrete tax benefit driven by a tax rate change in a foreign jurisdiction.

In addition, the significant increase in the deferred income tax benefit for the nine months ended September 30, 2017 is primarily due to the loss recorded for the Marcellus Shale upstream divestiture during second quarter 2017.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2014, Israel – 2015 and Equatorial Guinea – 2012.

Deferred Tax Assets We currently forecast that our US federal income tax net operating loss (NOL) carryforwards will be substantial at year end 2017.

Included in the resulting deferred tax assets are acquired deferred tax assets associated with net operating losses of the Clayton Williams Energy Acquisition in 2017 and with the Rosetta Resources Inc. acquisition in 2015.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income in the associated tax jurisdictions during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, current financial position, results of operations, projected future taxable income and tax planning strategies, as well as current and forecasted business economics in the oil and gas industry. Based on the level of our historical taxable income and projections for future taxable income, we currently believe it is more likely than not that we will realize the benefits of these NOL carryforwards. However, the amount of the deferred tax assets

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

considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

We currently have a valuation allowance on the deferred tax assets associated with foreign loss carryforwards forecasted for year end 2017 of approximately \$181 million at September 30, 2017 and \$242 million at December 31, 2016. The decrease was attributable to the offset of the valuation allowance against the net operating loss in a jurisdiction in which we are no longer active.

Note 11. Segment Information

During second quarter 2017, as a result of the strategic changes in our US onshore portfolio, we established our Midstream business as a new reportable segment. The Midstream segment, which includes the consolidated accounts of Noble Midstream Partners, additional US onshore midstream assets and US onshore equity method investments, was previously reported within the United States reportable segment. As a result, as of June 30, 2017, we now have five reportable segments, United States (US onshore and Gulf of Mexico); Eastern Mediterranean (Israel and Cyprus); West Africa (Equatorial Guinea, Cameroon and Gabon); Other International (Falkland Islands, Suriname, Canada and New Ventures); and Midstream.

The geographical reportable segments are in the business of crude oil and natural gas exploration, development, production, and acquisition (Oil and Gas Exploration and Production). The Midstream reportable segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins. The Corporate reportable segment incurs expenses related to debt, headquarters depreciation and corporate general and administrative cost.

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

Prior period amounts are presented on a comparable basis.

<i>(In millions)</i>	Oil and Gas Exploration and Production					Midstream		Intersegment Eliminations and Other		Corporate
	Consolidated	United States	Eastern Mediterranean	West Africa	Other Int'l (1)	United States	Other			
Three Months Ended September 30, 2017										
Oil, NGL and Gas Sales from Third Parties	\$ 907	\$ 696	\$ 141	\$ 70	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Income from Equity Method Investees and Other	53	—	—	33	—	20	—	—	—	—
Intersegment Revenues	—	—	—	—	—	72	(72)	—	—	—
Total Revenues	960	696	141	103	—	92	(72)	(72)	—	—
Lease Operating Expense	151	118	9	25	—	—	(1)	—	—	—
Production and Ad Valorem Taxes	36	35	—	—	—	1	—	—	—	—
Gathering, Transportation and Processing Expense	93	129	—	—	—	20	(56)	—	—	—
Total Production Expense	280	282	9	25	—	21	(57)	(57)	—	—
DD&A	523	442	18	41	1	10	(1)	—	—	12
Loss on Marcellus Shale Upstream Divestiture	4	4	—	—	—	—	—	—	—	—
Clayton Williams Energy Acquisition Expenses	4	4	—	—	—	—	—	—	—	—
Loss on Commodity Derivative Instruments	22	16	—	6	—	—	—	—	—	—
(Loss) Income Before Income Taxes (2)	(208)	(115)	109	24	23	58	(12)	(12)	(295)	(295)
Three Months Ended September 30, 2016										
Oil, NGL and Gas Sales from Third Parties	\$ 882	\$ 638	\$ 150	\$ 94	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Income from Equity Method Investees and Other	28	—	—	19	—	9	—	—	—	—
Intersegment Revenues	—	—	—	—	—	57	(57)	—	—	—
Total Revenues	910	638	150	113	—	66	(57)	(57)	—	—
Lease Operating Expense	131	106	8	22	—	—	(5)	—	—	—
Production and Ad Valorem Taxes	30	29	—	—	—	1	—	—	—	—
Gathering, Transportation and Processing Expense	121	144	—	—	—	11	(34)	—	—	—
Total Production Expense	282	279	8	22	—	12	(39)	(39)	—	—
DD&A	621	536	22	46	1	5	—	—	—	11
Loss on Commodity Derivative Instruments	(55)	(48)	—	(7)	—	—	—	—	—	—
(Loss) Income Before Income Taxes (2)	(280)	(255)	135	48	(33)	47	(18)	(18)	(204)	(204)

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

<i>(In millions)</i>	Consolidated	Oil and Gas Exploration and Production				Midstream		Intersegment Eliminations and Other	Corporate
		United States	Eastern Mediterranean	West Africa	Other Int'l ⁽¹⁾	United States			
Nine Months Ended September 30, 2017									
Oil, NGL and Gas Sales from Third Parties	\$ 2,918	\$ 2,246	\$ 406	\$ 266	\$ —	\$ —	\$ —	\$ —	\$ —
Income from Equity Method Investees and Other	137	—	—	84	—	53	—	—	—
Intersegment Revenues	—	—	—	—	—	198	(198)	—	—
Total Revenues	3,055	2,246	406	350	—	251	(198)	—	—
Lease Operating Expense	414	332	23	65	—	—	(6)	—	—
Production and Ad Valorem Taxes	119	117	—	—	—	2	—	—	—
Gathering, Transportation and Processing Expense	333	416	—	—	—	53	(136)	—	—
Total Production Expense	866	865	23	65	—	55	(142)	—	—
DD&A	1,554	1,326	58	114	4	20	(2)	34	—
Loss on Marcellus Shale Upstream Divestiture	2,326	2,326	—	—	—	—	—	—	—
Clayton Williams Energy Acquisition Expenses	98	98	—	—	—	—	—	—	—
Gain on Commodity Derivative Instruments	(145)	(138)	—	(7)	—	—	—	—	—
(Loss) Income Before Income Taxes⁽²⁾	(2,483)	(2,433)	316	162	11	165	(47)	(657)	—
Nine Months Ended September 30, 2016									
Oil, NGL and Gas Sales from Third Parties	\$ 2,411	\$ 1,705	\$ 407	\$ 299	\$ —	\$ —	\$ —	\$ —	\$ —
Income from Equity Method Investees and Other	70	—	—	31	—	39	—	—	—
Intersegment Revenues	—	—	—	—	—	143	(143)	—	—
Total Revenues	2,481	1,705	407	330	—	182	(143)	—	—
Lease Operating Expense	412	324	25	75	—	—	(12)	—	—
Production and Ad Valorem Taxes	73	70	—	—	—	3	—	—	—
Gathering, Transportation and Processing Expense	354	417	—	—	—	31	(94)	—	—
Total Production Expense	839	811	25	75	—	34	(106)	—	—
DD&A	1,859	1,599	62	150	4	14	—	30	—
Loss on Commodity Derivative Instruments	53	45	—	8	—	—	—	—	—
(Loss) Income Before Income Taxes⁽²⁾	(1,231)	(1,076)	290	74	(98)	126	(37)	(510)	—
September 30, 2017									
Goodwill ⁽³⁾	\$ 1,295	\$ 1,295	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Total Assets	21,649	16,287	2,681	1,265	108	1,158	(142)	292	—
December 31, 2016									
Total Assets	21,011	16,153	2,233	1,479	89	851	(98)	304	—

⁽¹⁾ Income before income taxes for the three and nine months ended September 30, 2017 primarily relates to the North Sea remediation project revision. See [Note 2. Basis of Presentation](#) and [Note 9. Asset Retirement Obligations](#).

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

(2) The intersegment eliminations related to (loss) income before income taxes are the result of midstream expenditures. These costs are presented as property, plant and equipment within the upstream business on an unconsolidated basis, in accordance with the successful efforts method of accounting, and are eliminated upon consolidation.

(3) Goodwill in our United States reportable segment is associated with our Texas reporting unit. See [Note 2. Basis of Presentation](#).

Note 12. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

Marcellus Shale Firm Transportation Contracts In connection with the Marcellus Shale upstream divestiture, we reduced our firm transportation commitment through transfer of certain contracts to the acquirer.

We retained certain other firm transportation contracts representing a total financial commitment of approximately \$1.6 billion, undiscounted, primarily with remaining contract terms of 15 years. Of this amount, approximately \$627 million, undiscounted, relates to two pipeline projects which are currently under construction and targeted to be placed in service mid-to-late fourth quarter 2017. We are in negotiations with third parties for the commercialization and permanent assignment or release of a portion of our capacity under these contracts which would reduce our undiscounted financial commitment. As these pipeline projects become commercially available to us and our commitment begins, we will evaluate our position, commercialization activities and ability to utilize retained capacity. If we determine that we will not utilize a portion, or all, of the contracted and retained pipeline capacity, we will accrue a liability, at fair value, for the net amount of the estimated remaining financial commitment and include the related expense in operating expense in our consolidated statements of operations. At this time, we are unable to predict with certainty the outcome of our commercialization activities, our ability to utilize retained capacity and the timing of when we may recognize a non-cash exit cost in line with accounting for exit costs associated with these two pipeline projects. See [Note 2. Basis of Presentation](#).

The remaining commitments relate to two additional pipeline projects that are targeted to be placed in service late 2018, one of which has not yet been approved by the FERC. We continue to monitor and assess the status of these pipeline projects, including regulatory approval and construction progress, and are evaluating commercialization options.

We cannot guarantee our commercialization efforts will be successful and we may recognize substantial future liabilities, at fair value, for the net amount of the estimated remaining commitments under these contracts. These financial commitments are included in the table below consistent with expected future cash payments associated with the underlying agreements. See [Note 4. Acquisitions and Divestitures](#).

Non-Cancelable Leases and Other Commitments We hold leases and other commitments for drilling rigs, buildings, equipment and other property and have entered into numerous long-term contracts for gathering, processing and transportation services. Minimum commitments have been updated to give effect to the Clayton Williams Energy Acquisition, the Marcellus Shale upstream divestiture, as well as commitments related to Leviathan development activities, and consist of the following as of September 30, 2017:

<i>(millions)</i>	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations ⁽¹⁾	Operating Lease Obligations	Capital Lease Obligations ⁽²⁾	Total
October - December 2017	\$ 136	\$ 53	\$ 12	\$ 20	\$ 221
2018	425	247	43	74	789
2019	148	276	32	45	501
2020	26	249	32	42	349
2021	7	213	32	29	281
2022 and Thereafter	36	1,499	189	145	1,869
Total	\$ 778	\$ 2,537	\$ 340	\$ 355	\$ 4,010

⁽¹⁾ Includes approximately \$1.6 billion of future cash payments related to retained Marcellus Shale firm transportation contracts. See discussion above.

⁽²⁾ Annual lease payments, net to our interest, exclude regular maintenance and operating costs. See [Note 6. Debt](#).

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 also being expended in accordance with schedules established in the Consent Decree. During 2015 and 2016, we spent approximately \$54.7 million to undertake injunctive relief at certain tank systems following the outcome of adequacy of design evaluations and certain operation and maintenance activities to handle potential peak instantaneous vapor flow rates. Future costs associated with injunctive relief are not yet precisely quantifiable as we are continually evaluating various approaches to meet the ongoing obligations of the Consent Decree.

Overall compliance with the Consent Decree has resulted in the temporary shut-in and permanent plugging and abandonment of certain wells and associated tank batteries. Consent Decree compliance could result in additional temporary shut-ins and 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 that may be extended depending on certain situations. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that

which is required under existing Colorado regulations.

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 Water Quality Control Division Matter In January 2017, we received a Notice of Violation/Cease and Desist Order (NOV/CDO) advising us of alleged violations of the Colorado Water Quality Control Act (Act) and its implementing regulations as it relates to our Colorado Discharge Permit System General Permit for construction activities associated with oil and gas exploration and /or production within our Wells Ranch Drilling and Production field located in Weld County, Colorado (Permit). The NOV/CDO further orders us to cease and desist from all violations of the Act, the regulations and the Permit and to undertake certain corrective actions. Given the uncertainty associated with administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time but believe that the resolution of this action will not have a material adverse effect on our financial position, results of operations or cash flows.

Colorado Air Compliance Order on Consent In April 2017, 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 compliance testing of certain engines subject to various General Permit 02 conditions and/or individual permit conditions. In May 2017, we reached a final resolution with the APCD and executed the COC, which requires payment of a civil penalty of \$24,710 and an expenditure of no less than \$98,840 on an approved SEP(s). This resolution is not believed to have a material adverse effect on our financial position, results of operations or cash flows.

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 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 – E&P](#);
- [Results of Operations – Midstream](#);
- [Liquidity and Capital Resources](#); and
- [Critical Accounting Policies and Estimates, Update](#).

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

EXECUTIVE OVERVIEW

The following discussion highlights significant operating and financial results for third quarter 2017. This discussion should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2016, which includes disclosures regarding our critical accounting policies as part of "Management's Discussion and Analysis of Financial Condition and Results of Operations."

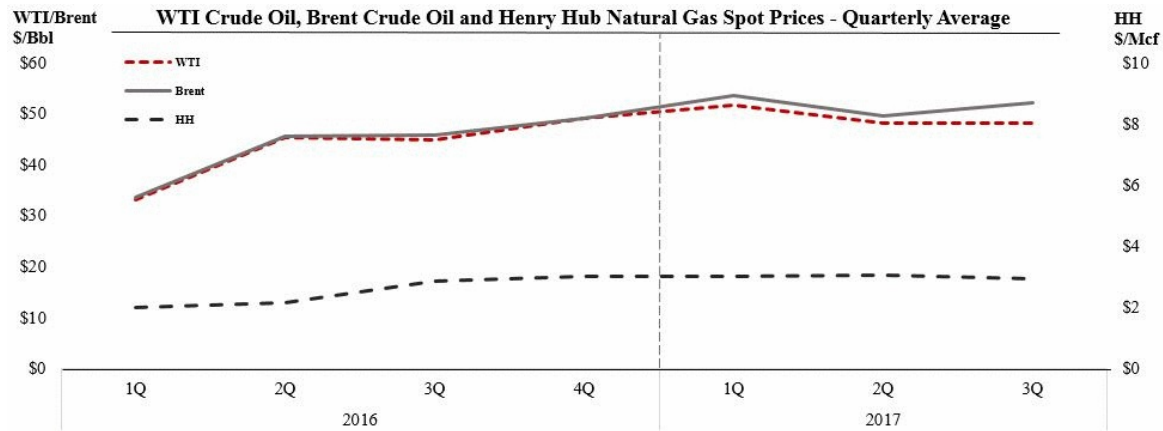
Current Upstream Environment

Crude Oil Prices Crude oil prices strengthened during third quarter 2017 lifting the West Texas Intermediate (WTI) to settlements above \$50 per barrel, consistent with prices seen earlier in the year, and the Brent index rallied with a two-year high of nearly \$60 per barrel. The increase in crude oil prices provides evidence of rebalancing between supply and demand. On the supply side, certain global producers continue to adhere to production cuts in an attempt to lower excess supply, while global demand has increased driven by usage in refineries and consumption in the European and US markets.

For the remainder of 2017, inventory and production levels, particularly US onshore supply growth and the effectiveness of OPEC-led curtailment actions, as well as OPEC production from countries not bound to OPEC curtailments, such as Libya and Nigeria, are likely to be the primary determinants of near-term crude oil prices with the risk that strong production trends cause crude oil prices to remain capped or possibly decline. Adherence to current and possible future OPEC decisions regarding extension of production curtailments, changes in crude oil storage levels and US shale oil production trends, are likely to continue to have significant impacts on crude oil prices.

Natural Gas Prices The US domestic natural gas market remains oversupplied as domestic production has continued to grow due to drilling efficiencies, completion of drilled but uncompleted well inventory and de-bottlenecking of transportation infrastructure. In contrast to crude oil supply curtailments, there has been little to offset natural gas supply growth, which continues to outpace natural gas demand domestically. As a result, during the first nine months of 2017, natural gas prices remained range bound. We expect this situation to continue for the remainder of 2017, with natural gas prices near current or recent trading levels.

Price Trend Chart The chart below shows the historical trend in benchmark prices for WTI crude oil, Brent crude oil and U.S. Henry Hub natural gas.



Development and Operating Costs Third party oilfield service and supply costs are also subject to supply and demand dynamics. During the first nine months of 2017, increases in US onshore drilling and completion activity resulted in higher demand for oilfield services. As a result, the costs of drilling, equipping and operating wells and infrastructure have begun to experience some inflation, which, along with the current commodity prices noted above, results in continued pressures on industry operating margins. Conversely, the industry has reduced capital-intensive offshore exploration and drilling activities in response to the commodity price environment. As a result, demand for and costs associated with offshore services have declined and in the near-term, will likely not be subject to cost inflation.

Recent Achievements

Despite the current commodity price and cost environment, Noble Energy has had a very successful 2017 thus far, achieving several strategic, operational and financial goals. Strategically, we closed several transformative portfolio transactions demonstrating our continued focus on enhancing margins and project returns. Operationally, we continued to enhance US onshore drilling and completions and advanced our Eastern Mediterranean regional natural gas developments. Financially, we continued to maintain our strong balance sheet and liquidity position.

Clayton Williams Energy Acquisition On April 24, 2017, we completed the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) for \$2.5 billion of stock and cash consideration. In connection with the acquisition, we assumed, and then subsequently retired, \$595 million of Clayton Williams Energy long-term debt. The transaction adds highly contiguous acreage in the core of the Delaware Basin and materially expands our Delaware position to approximately 118,000 net acres. The integration of the Clayton Williams Energy assets into our portfolio expands our opportunities in the core, high crude oil content area of the Delaware Basin, significantly increasing our US onshore growth outlook. See [Item 1. Financial Statements – Note 3. Clayton Williams Energy Acquisition](#).

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of the Marcellus Shale upstream assets, receiving net proceeds of \$1.0 billion. The divestment enables us to further focus our organization on our highest-return areas that are expected to deliver US onshore volume and cash flow growth. In addition, we have signed a definitive agreement to divest our Marcellus Shale midstream business for \$765 million. See [Item 1. Financial Statements – Note 4. Acquisitions and Divestitures](#) and [Note 12. Commitments and Contingencies](#).

Midstream Growth Along with our upstream portfolio actions, we continued to grow our Midstream business and completed our first drop-down transaction of midstream assets to Noble Midstream Partners L.P. (NBLX) for total consideration of \$270 million.

Operational Accomplishments Operationally, we delivered quarterly sales volumes of 355 MBoe/d with approximately 54% of our production mix attributable to crude oil and NGLs, established an all-time record for quarterly gross sales volumes of 997 MMcfe/d in Israel primarily from the Tamar field and continued to progress the Leviathan development project within budget towards first natural gas production by the end of 2019. See Project Updates, below, and Result of Operations.

Financial Flexibility, Liquidity and Balance Sheet Strength We continue to undertake proactive and strategic actions to maintain liquidity and a strong balance sheet. During third quarter 2017, for example, we engaged in debt refinancing activities

which collectively enhance our financial flexibility and result in future interest expense savings. In addition, during second quarter 2017, we utilized proceeds received from the Marcellus Shale upstream divestiture and NBLX drop-down transaction to offset the cash impact of the Clayton Williams Energy Acquisition. Proceeds received from these transactions were used to retire \$1.3 billion borrowed under our Revolving Credit Facility to pay for the cash consideration of the Clayton Williams Energy Acquisition and associated costs, as well as the retirement of all \$595 million of assumed Clayton Williams Energy debt. We strive to maintain a robust liquidity position and ended third quarter 2017 with approximately \$4.3 billion of liquidity, which includes cash on hand and unused borrowing capacity. See Liquidity and Capital Resources.

Positioned for the Future

We believe the following guiding principles will contribute to the sustainability and success of our business throughout the commodity price cycle, including extended periods of lower prices:

- Execution of a disciplined capital allocation process by:
 - designing a flexible investment program aligned with the current commodity price environment; and
 - maintaining a strong balance sheet and liquidity position.
- Enhancing capital efficiencies through:
 - utilizing our technical competencies and applying historical learnings from unconventional US shale plays to reduce US onshore finding and development costs; and
 - driving Delaware Basin economics through development cycle efficiencies.
- Leveraging the benefits of our well-positioned and diversified portfolio including:
 - exercising investment optionality and flexibility afforded by our assets held by production; and
 - continuing portfolio optimization actions to maximize strategic value.
- Capitalizing on a currently low-cost offshore environment with execution of high-quality long-cycle development projects, such as:
 - sanctioning and commencing the first phase of Leviathan field development.
- Maintaining financial strength through:
 - focusing operational activities on high-margin, high-return assets;
 - improving overall corporate returns; and
 - ensuring cash flow sources and uses remain balanced.

In summary, as we progress through the remainder of 2017, we believe we are positioned for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. We remain committed to maintaining capital discipline and financial strength and will continuously evaluate commodity prices along with well productivity and efficiency gains as we optimize our activity levels in alignment with commodity price conditions.

To this end, our 2017 capital investment program is responsive to positive or negative commodity price conditions that may develop. Excluding acquisition and Noble Midstream Partners capital, we expect our 2017 capital spending program to be in the upper end of our investment range of \$2.3 to \$2.6 billion, or approximately 50% higher than 2016. See [Operating Outlook – 2017 Capital Investment Program](#), below.

Although the industry has begun to recover from the recent downturn, if commodity prices decline or operating costs begin to rise, we could experience material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and in response, we may consider reductions in our capital program or dividends, asset sales or cost structure. Our production and our stock price could decline as a result of these potential developments.

Recently Issued Accounting Standards

See [Item 1. Financial Statements – Note 2. Basis of Presentation](#).

OPERATING OUTLOOK

2017 Production Our expected crude oil, natural gas and NGL production for the remainder of 2017 may be impacted by several factors including:

- commodity prices which, if subject to a significant 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;
- with increased drilling activity, US onshore cost inflation pressure may result in certain current production becoming less profitable or uneconomic;

- 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 a portion of our working interest in the Tamar field, in accordance with the Israel Natural Gas Framework (Framework), which will lower our sales volumes;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa as well as the unitization of the Alba field;
- additional purchases of producing properties or divestments of operating assets;
- natural field decline in the US onshore, Gulf of Mexico and offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the Gulf of Mexico and Gulf Coast areas, or winter storms and flooding impacting US onshore operations;
- availability or reliability of supplier services, including access to support equipment and facilities, occurrence of pipeline disruptions, and/or potential pipeline and processing facility capacity constraints which may cause delays, restrictions or interruptions in production and/or midstream processing;
- timing and completion of midstream expansion projects by Noble Midstream Partners in areas that provide services to our assets;
- malfunctions and/or mechanical failures at terminals or other US onshore delivery points;
- impact of enhanced completion efforts for US onshore assets;
- possible abandonment of low-margin US onshore wells;
- shut-in of US producing properties if storage capacity becomes unavailable; and
- drilling and/or completion permit delays due to future regulatory changes.

2017 Capital Investment Program Given the current commodity price environment, we have designed a flexible capital investment program as part of our comprehensive effort to maintain strong liquidity and manage the Company's balance sheet. Excluding acquisition capital and Noble Midstream Partners, we expect our 2017 capital investment program to be in the upper end of our range of \$2.3 to \$2.6 billion, of which \$1.9 billion has been incurred during the nine months ended September 30, 2017. More than 75% of the total capital investment program is allocated to US onshore development primarily in liquids-rich opportunities in the DJ Basin, Delaware Basin, and Eagle Ford Shale. The remaining 25% capital investment program will be predominately allocated to the Eastern Mediterranean, including initial development costs associated with the Leviathan project.

See [Liquidity and Capital Resources – Financing Activities](#), below.

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

Exploration Activities and Unproved Properties Our exploration program seeks to provide growth through long-term and/or large-scale exploration opportunities. We continue to seek exploration opportunities in various geographical areas, such as our entry into Newfoundland, Canada. In other areas of the world, we have capitalized a significant amount of exploratory drilling costs. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery or prospect is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. As of September 30, 2017, we have capitalized costs related to exploratory wells of \$575 million. See [Item 1. Financial Statements - Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs](#) and [Results of Operations – Oil and Gas Exploration Expense](#), below.

We may also impair and/or relinquish certain undeveloped leases prior to expiration, based upon geological evaluation or other factors. For example, during the first nine months of 2017, we impaired \$49 million of assets related to certain Gulf of Mexico undeveloped leases. We have numerous leases for Gulf of Mexico prospects that have not yet been drilled. A significant portion of these leases are scheduled to expire over the years 2018 to 2020 and some leases may become impaired if production is not established, no action is taken to extend the terms of the leases, or the leases become uneconomic due to low commodity prices or other factors.

In addition, we have undeveloped leasehold costs, to which proved reserves had not been attributed, of \$3.0 billion. Of this amount, \$1.6 billion is attributable to Delaware Basin assets acquired in the Clayton Williams Energy Acquisition in 2017, and \$1.1 billion and \$149 million are attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition in 2015. These costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and are subject to impairment testing utilizing a future cash flows analysis.

The remaining undeveloped leasehold costs as of September 30, 2017 included \$56 million related to Gulf of Mexico unproved properties and \$53 million related to international unproved properties. These costs are evaluated as part of our periodic impairment review. If, based upon a change in exploration plans, timing and extent of development activities, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other

Table of Contents

factors, an impairment is indicated, we will record impairment expense related to the respective leases. As a result of our exploration activities, future exploration expense, including undeveloped leasehold impairment expense, could be significant. See [Results of Operations - Oil and Gas Exploration Expense](#), below.

Proved Properties During the first nine months of 2017, no impairments were incurred related to proved properties. 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, 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, in third quarter 2017, we recorded a revision of \$42 million that decreased our estimated asset retirement obligation for the North Sea remediation project from \$87 million to \$45 million. The revision was a result of a more precise estimate received from the operator based upon their completion of activities performed to-date, as well as due to revised timing and scope of the remediation work. We will continue to monitor the status and costs of the project as the operator progresses with decommissioning activities and will adjust our estimate accordingly. The revision is included in other operating expense, net in the consolidated statement of operations. See [Item 1. Financial Statements - Note 2. Basis of Presentation](#) and [Item 1. Financial Statements - Note 9. Asset Retirement Obligations](#).

Divestments We actively manage our asset portfolio to ensure our assets are well-positioned on the industry cost of supply curve and offer growth at financially attractive rates of return. Therefore, we may periodically divest certain assets, such as the Marcellus Shale upstream assets, to reposition our portfolio. Proceeds from asset sales are redeployed in our capital investment program, used to pay down debt, strengthen our balance sheet and/or support returns to shareholders through dividends or other mechanisms.

When properties meet the criteria for reclassification as assets held for sale, they are valued at the lower of net book value or anticipated sales proceeds less transaction related costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less transaction related costs to sell.

We strive to obtain the most advantageous price for any asset divestment; however, various factors, such as current and future commodity prices, reserves, production profiles, operating costs, capital investment requirements and potential future liabilities, as well as legal and regulatory requirements, can make it difficult to predict an asset's selling price and whether a transaction will result in a gain or loss. Inability to achieve a desired sales price, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a possible loss on the sale, which could be material. See [Item 1. Financial Statements - Note 4. Acquisitions and Divestitures](#).

We continue to review our portfolio to ensure alignment with the aforementioned strategic objectives. Further, the State of Israel requires that 7.5% of our working interest in the Tamar field offshore Israel be divested by December 2021, reducing our working interest from 32.5% to 25%. Additional potential divestments may be considered, even though no commitments have been made by our management and our Board of Directors.

Deferred Income Taxes We currently forecast that our US federal income tax net operating loss (NOL) carryforwards will be substantial at year end 2017. Included in the resulting deferred tax assets are acquired deferred tax assets associated with net operating losses of the Clayton Williams Energy Acquisition in 2017 and with the Rosetta Resources Inc. acquisition in 2015.

We have established a valuation allowance against the deferred tax asset associated with foreign and certain state NOLs, and we could be required to record an additional valuation allowance against deferred tax assets if market conditions change materially and, as a result, our future earnings are, or are projected to be, significantly less than we currently estimate. Any increase or decrease in the deferred tax asset valuation allowance would impact net income (loss) through offsetting changes in income tax expense (benefit), which could have a negative impact on our financial position and results of operations.

Regulatory Update

US Regulatory Developments In early 2017, President Trump issued two executive orders directing the US Environmental Protection Agency (EPA) and other executive agencies to review their rules and policies that unduly burden domestic energy development. Specifically, on February 28, 2017, President Trump signed an executive order directing the EPA and the US Army Corps of Engineers (Corps) to review the Clean Water Rule and to initiate rulemaking to rescind or revise it, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On March 28, 2017, President Trump signed an executive

order directing the EPA and other executive agencies to review all regulations, orders, guidance documents and policies and take actions to suspend, revise or rescind them, as appropriate and consistent with the law, to the extent that they unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest.

Pursuant to the first executive order, on June 27, 2017, the EPA and the Corps announced a proposed rule to rescind the Clean Water Rule and to re-codify the regulations that existed before the Clean Water Rule. Consistent with the second executive order, on June 5, 2017, the EPA published notice that it would reconsider certain requirements of a May 2016 rule, which set standards for emissions of methane and volatile organic compounds from new and modified oil and gas production sources, and that it would stay for 90 days those requirements pending reconsideration. On June 16, 2017, the EPA published a proposed rule to extend the stay for two years. On July 3, 2017, the D.C. Circuit Court of Appeals vacated the 90-day stay, but noted that this decision did not limit the EPA's authority to reconsider its regulations and proceed with the June 16, 2017 proposed rulemaking. Also, on July 25, 2017, the Bureau of Land Management (BLM) published a proposed rule to rescind its March 2015 rules governing hydraulic fracturing on federal and Indian lands. The EPA and the BLM have also announced that they are reconsidering, or plan to reconsider, additional regulations that impact the oil and gas industry. However, it remains unclear how and to what extent this broad review could impact environmental regulations at the federal level.

Voluntary Withdrawal from International Climate Change Accord In December 2015, the United States signed the Paris Agreement on climate change and pledged to take efforts to reduce greenhouse gas (GHG) emissions and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement entered into force in November 2016. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. While President Trump expressed a clear intent to cease implementing the Paris Agreement, it is not clear how the Administration plans to accomplish this goal, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders stated their intent to intensify efforts to uphold the commitments set forth in the international accord. It is not possible at this time to predict the timing or effect of international treaties or regulations on our operations or to predict with certainty the future costs that we may incur in order to comply with such treaties or regulations.

Impact of Dodd-Frank Act Section 1504 In June 2016, the Securities and Exchange Commission (SEC) adopted resource extraction issuer payment disclosure rules under Section 1504 of the Dodd-Frank Act that would have required resource extraction companies, such as us, to publicly file with the SEC beginning in 2019 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 development of crude oil, natural gas or minerals, and the type and total amount of payments made to each government (such rules, the Resource Extraction Issuer Payment Rules).

However, on February 14, 2017, President Trump signed a joint resolution passed by the United States Congress under the Congressional Review Act and eliminated the Resource Extraction Issuer Payment Rules. It should be noted that Section 1504 of the Dodd-Frank Act has not been repealed and that the SEC will now have until February 2018 to issue replacement rules to implement Section 1504 of the Dodd-Frank Act, and that under the Congressional Review Act a rule may not be issued in "substantially the same form" as the disapproved rule unless it is specifically authorized by a subsequent law. We cannot predict whether the SEC will issue replacement rules or, if it does so, whether such replacement rules will again be eliminated pursuant to the Congressional Review Act.

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

EXPLORATION AND PRODUCTION (E&P)

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. Third quarter 2017 activities included the following:

DJ Basin (US Onshore) Our activities during third quarter 2017 were focused primarily in Wells Ranch and East Pony where we operated an average of two drilling rigs, drilled 32 wells and commenced production on 32 wells. We continue to optimize value in these oil-rich areas through our horizontal development program, which has led to an increasing mix of crude oil sales volumes and a new record crude oil mix of 54% in the DJ Basin during third quarter 2017, slightly higher than the prior quarter. While we expect our total horizontal production to continue to grow for the remainder of 2017, we anticipate certain of our legacy horizontal wells, as well as the majority of our vertical wells, to experience production declines as we enhance our focus on horizontal development in the oil-rich areas of the basin.

Delaware Basin (US Onshore) During third quarter 2017, we operated an average of five drilling rigs, drilled 17 horizontal wells and commenced production from 14 wells with the majority of our activity focused on long laterals and multi-well pads targeting multiple zones within the basin. We averaged 27 MBoe/d of sales volumes during third quarter 2017 with 85% our production mix attributable to crude oil and NGLs. Our integration and assumption of operations of the Clayton Williams Energy assets in second quarter 2017 continues to be successful as we apply learnings from our legacy Delaware Basin assets across the play to optimize our development plan, realize cost efficiencies, enhance completion designs and optimize well placement, thereby positively impacting costs and performance associated with these assets.

Eagle Ford Shale (US Onshore) Our activity in Webb and Dimmit Counties during third quarter 2017 was focused on well completion activities for previously drilled wells and we commenced production on 12 wells during the quarter. We continue to execute a strong development plan and surpass previous quarterly sales volumes records, including averaging sales volumes of 76 MBoe/d during third quarter 2017 despite multiple weather-related events causing the temporary suspension and shut-in of production across our Eagle Ford Shale assets. After inspection and safe return to operations, the impact of these weather-related events reduced our sales volumes by approximately 5 MBoe/d for third quarter 2017. For the remainder of 2017, we expect sales volumes to grow in this liquids-rich play.

Gulf of Mexico (US Offshore) Our offshore assets continue to provide high-margin oil production, and during third quarter 2017, average daily sales volumes were 25 MBoe/d. In July, the Gunflint field surpassed its one-year anniversary of first production. Also, during the third quarter, the Company exceeded more than one year of offshore performance without a recordable safety incident in either production operations or at the Company's operated facilities.

Tamar Natural Gas Project (Offshore Israel) Growth in power and industrial demand in Israel, resulting from the increased use of natural gas over coal to fuel power generation, enabled us to set a new all-time record for average daily gross sales volumes of 997 MMcf/d during third quarter 2017 primarily from the Tamar field. We achieved this record despite planned maintenance procedures performed at the Tamar platform in late September 2017. During these procedures, we identified and completed additional modifications to the venting system, which resulted in a controlled full-field shut-down. All facility maintenance was completed safely and timely with no material impact to sales volumes. Our active response, coupled with operational uptime of approximately 97% for 2017, as well as the commencement of production from the Tamar 8 well earlier in the year, reflect our continued commitment to reliably and consistently deliver natural gas to Israeli customers.

In third quarter 2017, we completed additional reservoir modeling reflecting integration of Tamar 8 well results into our geologic modeling across the reservoir and, as a result, we added one Tcfe, gross, or 48 MMBoe, net, of proved developed natural gas reserves as of September 30, 2017. In accordance with the terms of the Framework, we continue to market a portion of our working interest in Tamar, which provides for reduction in our ownership interest to 25% by year-end 2021.

Leviathan Natural Gas Project (Offshore Israel) The first phase of development of the Leviathan field provides 1.2 Bcf/d of production capacity and consists of four wells, a subsea production system and a shallow-water processing platform, with a connection to an onshore valve station and the Israel Natural Gas Lines (INGL) pipeline network. We expect our share of development costs to total approximately \$1.5 billion and to be funded from our share of cash flows from the Tamar asset and expected proceeds to be received from the sell-down of our ownership interest in Tamar as noted above. In addition, we have the ability to borrow under the Leviathan Term Loan Facility (defined below).

During third quarter 2017, we continued to progress the project within budget towards first gas by the end of 2019. We continued detailed design and engineering activities and fabrication of topsides, jacket and subsea equipment. We also commenced front-end engineering design (FEED) studies for the Hagit terminal, which will provide condensate storage and offloading facilities.

Table of Contents

As of September 30, 2017, the project remained on schedule at approximately 23% complete, with all critical path equipment and major contracts secured. We expect to continue drilling activities and commence well completion in 2018.

At June 30, 2017, we recorded initial proved reserves of 551 MMBoe associated with the first phase of development.

Alba Field Unitization (Offshore West Africa) In April 2017, we executed a unitization agreement on the Alba field with our partner and the Government of Equatorial Guinea. The agreement was between Alba Block and Block D interest owners. As a result of the unitization, our revenue interest going forward changed from 34% to 32%, and our non-operated working interest changed from 35% to 33%. As anticipated, our third quarter 2017 sales volumes from the Alba field were lower as a result of the unitization, and we expect the impact on our proved reserves and allocated future sales volumes to be de minimis. Total sales volumes across our West Africa assets averaged 63 MBoe/d for third quarter 2017, which was better than anticipated due to the conversion of two wells from natural gas injection to production at the Alba field during the third quarter.

Unsanctioned Development Projects

Tamar Expansion Project (Offshore Israel) We are engaged in the planning phase for the Tamar expansion project. The project would expand field deliverability from the current level of approximately 1.2 Bcf/d to up to 2.1 Bcf/d, a quantity that would allow for additional regional export. Expansion would include a third flow line component and additional producing wells. Timing of project sanction is dependent upon progress relating to domestic and regional marketing efforts of these resources.

Leviathan Expansion Project (Offshore Israel) The full field development of Leviathan will be accomplished through a phased approach. Current build-out and construction of the first phase of the Leviathan production assets allows for future cost-effective expansion. Through the expansion phase, field capacity would increase from currently planned capacity of 1.2 Bcf/d to up to 2.1 Bcf/d through the addition of multiple process trains, a third subsea tieback flow line and a potential export pipeline, allowing for regional exports. Similar to the Tamar expansion project, sanction of Leviathan expansion is dependent upon both domestic and regional marketing efforts of these resources.

Cyprus Natural Gas Project (Offshore Cyprus) We continue to work with the Government of Cyprus on a plan of development for the Aphrodite field that, as currently planned, would deliver natural gas to potential regional customers. In addition, we are focused on natural gas marketing efforts and execution of natural gas sales and purchase agreements which, once secured, will progress the project to a final investment decision.

West Africa Natural Gas Monetization We continue our efforts to monetize our significant natural gas discoveries offshore West Africa. A natural gas development team has been working with local governments to evaluate natural gas monetization concepts. After analyzing existing infrastructure, including the Alen platform and other facilities, we believe these assets can be efficiently modified and retrofitted to allow for future commercialization of natural gas. Leveraging existing assets for the development of natural gas minimizes future capital expenditures while providing advantageous financial returns.

Given the monetization plan, to develop the Alen resources through existing infrastructure, we changed the units-of-production depletion rate, based on risked resources, during first quarter 2017. As a result, we proportionally allocated the book value associated with the existing infrastructure assets to the natural gas resources that will be developed in the future, resulting in approximately \$153 million of net asset value being reclassified as development costs not subject to depletion in first quarter 2017. See [Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments](#), above, and [Results of Operations - Operating Costs and Expenses](#), below.

Exploration Program Update

While our 2017 exploration budget has been substantially reduced compared to prior years due to the current commodity price environment, we continue to seek and evaluate opportunities for future exploration. For example, our partner spud the Araku-1 exploration well offshore Suriname in early October 2017 and subsequently plugged and abandoned the well. We own a 20% non-operating working interest in the well and anticipate our portion of costs to be less than \$10 million, which will be recorded as dry hole expense in fourth quarter 2017.

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 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs](#) and [Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments](#), above.

Results of Operations

Highlights for our E&P business were as follows:

Third Quarter 2017 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 355 MBoe/d;
- record average daily sales volumes for US onshore crude oil of 93 MBbl/d;
- average daily sales volumes of 285 MMcf/d, net, in Israel, and an all-time record for quarter average daily gross sales volumes of 997 MMcf/d, primarily from the Tamar field;
- natural gas sales volumes exceeding 1 Bcf/d, gross, for 79 days in Israel, primarily from the Tamar field; and
- an increase of one Tcfe, gross, or 48 MMBoe, net, of proved developed natural gas reserves for the Tamar field.

Third Quarter 2017 E&P Financial Results Included:

- average realized crude oil price increase of 13% as compared to 2016;
- average realized NGL price increase of 57% as compared to 2016;
- pre-tax income of \$41 million, as compared with pre-tax loss of \$105 million for third quarter 2016; and
- capital expenditures of \$596 million, excluding acquisitions, as compared with \$288 million for third quarter 2016.

Following is a summarized statement of operations for our E&P business:

<i>(millions)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Oil, NGL and Gas Sales from Third Parties	\$ 907	\$ 882	\$ 2,918	\$ 2,411
Income from Equity Method Investees	33	19	84	31
Total Revenues	940	901	3,002	2,442
Production Expense	316	309	953	911
Exploration Expense	64	125	136	376
Depreciation, Depletion and Amortization	502	605	1,502	1,815
Loss on Marcellus Shale Upstream Divestiture ⁽¹⁾	4	—	2,326	—
(Gain) Loss on Commodity Derivative Instruments	22	(55)	(145)	53
Clayton Williams Energy Acquisition Expenses ⁽²⁾	4	—	98	—
Income (Loss) Before Income Taxes	41	(105)	(1,944)	(810)

⁽¹⁾ See [Note 4. Acquisitions and Divestitures](#).

⁽²⁾ See [Note 3. Clayton Williams Energy Acquisition](#).

Oil, NGL and Gas Sales

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

	Sales Volumes				Average Realized Sales Prices			
	Crude Oil & Condensate (MBbl/d)	NGLs (MBbl/d)	Natural Gas (MMcf/d)	Total (MBoe/d) ⁽¹⁾	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)	
Three Months Ended September 30, 2017								
United States	114	56	449	244	\$ 46.63	\$ 22.88	\$ 2.23	
Israel	—	—	283	48	—	—	5.36	
Equatorial Guinea ⁽²⁾	13	—	246	54	51.32	—	0.27	
Total Consolidated Operations	127	56	978	346	47.13	22.88	2.65	
Equity Investees ⁽³⁾	2	7	—	9	52.69	37.49	—	
Total	129	63	978	355	\$ 47.27	\$ 24.56	\$ 2.65	
Three Months Ended September 30, 2016								
United States	99	55	874	299	\$ 41.23	\$ 14.70	\$ 2.38	
Israel	—	—	310	52	—	—	5.22	
Equatorial Guinea ⁽²⁾	22	—	261	65	43.73	—	0.27	
Total Consolidated Operations	121	55	1,445	416	41.67	14.70	2.61	
Equity Investees ⁽³⁾	2	7	—	9	45.72	23.65	—	
Total	123	62	1,445	425	\$ 41.75	\$ 15.66	\$ 2.61	
Nine Months Ended September 30, 2017								
United States	108	56	637	270	\$ 47.07	\$ 21.66	\$ 3.06	
Israel	—	—	276	46	—	—	5.33	
Equatorial Guinea ⁽²⁾	18	—	240	58	51.29	—	0.27	
Total Consolidated Operations	126	56	1,153	374	47.66	21.66	3.02	
Equity Investees ⁽³⁾	1	6	—	7	51.72	36.23	—	
Total	127	62	1,153	381	\$ 47.75	\$ 23.07	\$ 3.02	
Nine Months Ended September 30, 2016								
United States	99	56	902	304	\$ 37.23	\$ 13.38	\$ 2.00	
Israel	—	—	284	48	—	—	5.19	
Equatorial Guinea ⁽²⁾	25	—	230	64	40.74	—	0.27	
Total Consolidated Operations	124	56	1,416	416	37.94	13.38	2.36	
Equity Investees ⁽³⁾	2	5	—	7	43.95	24.43	—	
Total	126	61	1,416	423	\$ 38.02	\$ 14.32	\$ 2.36	

⁽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.

Table of Contents

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

<i>(millions)</i>	Sales Revenues			
	Crude Oil & Condensate	NGLs	Natural Gas	Total
Three Months Ended September 30, 2016	\$ 461	\$ 74	\$ 347	\$ 882
Changes due to				
Increase (Decrease) in Sales Volumes	26	1	(82)	(55)
Increase (Decrease) in Sales Prices	66	41	(27)	80
Three Months Ended September 30, 2017	\$ 553	\$ 116	\$ 238	\$ 907
Nine Months Ended September 30, 2016	\$ 1,291	\$ 204	\$ 916	\$ 2,411
Changes due to				
Increase (Decrease) in Sales Volumes	20	1	(135)	(114)
Increase in Sales Prices	326	124	171	621
Nine Months Ended September 30, 2017	\$ 1,637	\$ 329	\$ 952	\$ 2,918

Crude Oil and Condensate Sales Revenues Revenues from crude oil and condensate sales increased for third quarter 2017 as compared with 2016 due to the following:

- 13% increase in average realized prices due to the partial rebalancing of global supply and demand factors; and
 - higher US onshore sales volumes of 19 MBbl/d, including 7 MBbl/d contributed by recently acquired Clayton Williams Energy assets;
- partially offset by:
- lower sales volumes of 12 MBbl/d offshore US and West Africa due to the timing of liftings (7 MBbl/d) and natural field decline (5 MBbl/d) in the Gulf of Mexico and at Aseng and Alen, offshore Equatorial Guinea.

Revenues from crude oil and condensate sales increased for the nine months ended September 30, 2017 as compared with 2016 due to the following:

- 26% increase in average realized prices due to the partial rebalancing of global supply and demand factors;
 - higher US onshore sales volumes of 10 MBbl/d primarily in the DJ Basin and Delaware Basin, including 4 MBbl/d contributed by recently acquired Clayton Williams Energy assets; and
 - higher sales volumes of 4 MBbl/d from the Gunflint development, Gulf of Mexico, which began producing in July 2016;
- partially offset by:
- lower sales volumes of 11 MBbl/d due to natural field decline in the Gulf of Mexico and at Aseng and Alen, offshore Equatorial Guinea.

NGL Sales Revenues Revenues from NGL sales increased for third quarter 2017 as compared with 2016 due to the following:

- 57% increase in average realized prices due to the partial rebalancing of domestic supply and demand factors; and
 - higher sales volumes of 11 MBbl/d in the Delaware Basin and Eagle Ford Shale, primarily attributable to increased development and enhanced well design and completion techniques;
- partially offset by:
- lower sales volumes of 9 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Revenues from NGL sales increased for the nine months ended September 30, 2017 as compared with 2016 due to the following:

- 61% increase in average realized prices due to the partial rebalancing of domestic supply and demand factors; and
 - higher sales volumes of 4 MBbl/d in the Delaware Basin and Eagle Ford Shale primarily attributable to increased development and enhanced well design and completion techniques;
- partially offset by:
- lower sales volumes 3 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Natural Gas Sales Revenues Revenues from natural gas sales decreased for third quarter 2017 as compared with 2016 due to the following:

- a reduction of \$31 million related to previously recorded processing fees included within the US reportable segment;
- a 498 MMcf/d reduction in sales volumes due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;

Table of Contents

- lower sales volumes of 27 MMcf/d in the DJ Basin primarily attributable to increased focus on the oil-rich well locations of the basin;
 - lower sales volumes of 30 MMcf/d as a result of the sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016; and
 - lower sales volumes of 15 MMcf/d at the Alba field, offshore Equatorial Guinea, due to natural field decline;
- partially offset by:
- higher sales volumes of 85 MMcf/d in the Eagle Ford Shale primarily attributable to commodity mix from recently completed wells; and
 - higher sales volumes of 14 MMcf/d in the Delaware Basin primarily attributable to increased development and enhanced well design and completion techniques.

Revenues from natural gas sales increased for the nine months ended September 30, 2017 as compared with 2016 due to the following:

- 28% increase in average realized natural gas prices due to the partial rebalancing of domestic supply and demand factors;
 - higher domestic sales volumes of 41 MMcf/d in the Delaware Basin and Eagle Ford Shale combined, primarily attributable to increased development and enhanced completion techniques;
 - higher sales volumes of 16 MMcf/d offshore Israel, primarily attributable to higher production at the Tamar field; and
 - higher sales volumes of 10 MMcf/d at the Alba field, offshore Equatorial Guinea, following the startup of the B3 compression platform in July 2016;
- partially offset by:
- a reduction of \$31 million related to previously recorded processing fees included within the US reportable segment;
 - a 267 MMcf/d reduction in sales volumes due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;
 - lower sales volumes of 37 MMcf/d in the DJ Basin primarily attributable to increased focus on the oil-rich well locations of the basin; and
 - lower sales volumes of 29 MMcf/d as a result of the sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016, which is partially offset by higher gross field production.

Income from Equity Method Investees and Other 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 during the first nine months of 2017 as compared with 2016. The increase includes a \$29 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee, and a \$24 million increase from Alba Plant, our LPG investee, both primarily driven by rising commodity prices.

Production Expense Components of production expense from our upstream operations were as follows:

<i>(millions, except unit rate)</i>	Total per BOE (1) (2)	Total	United States (2)	Eastern Mediterranean	West Africa
Three Months Ended September 30, 2017					
Lease Operating Expense (3)	\$ 4.78	\$ 152	\$ 118	\$ 9	\$ 25
Production and Ad Valorem Taxes	1.10	35	35	—	—
Gathering, Transportation and Processing (4)	4.06	129	129	—	—
Total Production Expense	\$ 9.94	\$ 316	\$ 282	\$ 9	\$ 25
Total Production Expense per BOE		\$ 9.94	\$ 12.58	\$ 2.06	\$ 5.00
Three Months Ended September 30, 2016					
Lease Operating Expense (3)	\$ 3.55	\$ 136	\$ 106	\$ 8	\$ 22
Production and Ad Valorem Taxes	0.76	29	29	—	—
Gathering, Transportation and Processing (4)	3.76	144	144	—	—
Total Production Expense	\$ 8.07	\$ 309	\$ 279	\$ 8	\$ 22
Total Production Expense per BOE		\$ 8.07	\$ 10.16	\$ 1.67	\$ 3.67
Nine Months Ended September 30, 2017					
Lease Operating Expense (3)	\$ 4.12	\$ 420	\$ 332	\$ 23	\$ 65
Production and Ad Valorem Taxes	1.15	117	117	—	—
Gathering, Transportation and Processing (4)	4.08	416	416	—	—
Total Production Expense	\$ 9.35	\$ 953	\$ 865	\$ 23	\$ 65
Total Production Expense per BOE		\$ 9.35	\$ 11.76	\$ 1.82	\$ 4.12
Nine Months Ended September 30, 2016					
Lease Operating Expense (3)	\$ 3.72	\$ 424	\$ 324	\$ 25	\$ 75
Production and Ad Valorem Taxes	0.61	70	70	—	—
Gathering, Transportation and Processing (4)	3.66	417	417	—	—
Total Production Expense	\$ 7.99	\$ 911	\$ 811	\$ 25	\$ 75
Total Production Expense per BOE		\$ 7.99	\$ 9.72	\$ 1.91	\$ 4.30

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

(2) United States upstream production expense includes charges from our midstream operations that are eliminated on a consolidated basis. See [Item 1. Financial Statements – Note 11. Segment Information](#).

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

(4) Certain of our gathering and processing expenses were historically presented as components of other operating expense, net, in our consolidated statements of operations. Beginning in 2017, we have changed our presentation to reflect these as components of production expense. These costs are now included within gathering, transportation and processing expense. For the three and nine months ended September 30, 2017, these costs totaled \$12 million and \$17 million, respectively. For the three and nine months ended September 30, 2016, these costs totaled \$8 million and \$19 million, respectively, and have been reclassified from marketing expense to conform to the current presentation.

For third quarter 2017, total production expense increased as compared with 2016 due to the following:

- an increase in production and ad valorem taxes in the United States due to higher commodity prices;
- an increase in total production expense due to higher sales volumes in the Delaware Basin and the Eagle Ford Shale; and
- an increase in gathering, transportation and processing expense in the DJ Basin due to the shifting of crude oil volumes onto a new export pipeline and contractual increases of pipeline fees;

partially offset by:

- a decrease in lease operating expense due to natural field decline in the Gulf of Mexico; and
- a decrease in total production expense due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Table of Contents

For the first nine months of 2017, total production expense increased slightly as compared with 2016 due to the following:

- an increase in production and ad valorem taxes due to higher commodity prices;
- an increase in total production expense due to higher production in the Delaware Basin and Eagle Ford Shale; and
- an increase in production and ad valorem taxes due to a \$28 million US onshore severance tax refund recorded in first quarter 2016 versus a \$7 million US onshore severance tax charge recorded in first quarter 2017;

partially offset by:

- a decrease in total production expense due to natural field decline in the Gulf of Mexico;
- a decrease in lease operating expense due to a 3.5% lower working interest in the Tamar field, offshore Israel, following the partial divestiture in December 2016;
- a decrease in lease operating expense due to various cost reduction initiatives offshore West Africa; and
- a decrease in total production expense due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Production expense on a per BOE basis increased for the three and nine months ended September 30, 2017 compared to 2016 primarily due to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets in second quarter 2017, coupled with an increase in certain production expenses noted above. Specifically, the divestiture of the Marcellus Shale upstream assets removed lower-cost, natural gas-focused sales volumes from our portfolio, while an increase in volumes from the Delaware Basin and Eagle Ford Shale contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE. Also, higher commodity prices lead to higher production and ad valorem taxes per BOE.

Exploration Expense Our 2017 exploration budget has been substantially reduced compared to prior years due to the current commodity price environment. Exploration expense for the first nine months totaled \$136 million, including \$51 million of undeveloped leasehold impairment expense, of which \$49 million was attributable to our Gulf of Mexico leases. Other primary costs included staff expenses of \$40 million and seismic, geological and geophysical expenses of \$20 million.

Exploration expense for the first nine months of 2016 totaled \$376 million, including \$81 million of undeveloped leasehold impairment expense, of which \$56 million was attributable to our Gulf of Mexico leases and \$25 million attributable to the Falkland Islands. Dry hole cost totaled \$105 million and primarily related to the Silvergate exploratory well, Gulf of Mexico, and the Dolphin 1 natural gas discovery, offshore Israel. Other primary costs included staff expenses of \$53 million and seismic, geological and geophysical expenses of \$47 million.

Depreciation, Depletion and Amortization DD&A expense for our upstream operations was as follows:

<i>(millions, except unit rate)</i>	Total	United States	Eastern Mediter- ranean	West Africa	Other Int'l
Three Months Ended September 30, 2017					
DD&A Expense	\$ 502	\$ 442	\$ 18	\$ 41	\$ 1
Unit Rate per BOE ⁽¹⁾	\$ 15.79	\$ 19.72	\$ 4.11	\$ 8.19	\$ —
Three Months Ended September 30, 2016					
DD&A Expense	\$ 605	\$ 536	\$ 22	\$ 46	\$ 1
Unit Rate per BOE ⁽¹⁾	\$ 15.81	\$ 19.51	\$ 4.58	\$ 7.67	\$ —
Nine Months Ended September 30, 2017					
DD&A Expense	\$ 1,502	\$ 1,326	\$ 58	\$ 114	\$ 4
Unit Rate per BOE ⁽¹⁾	\$ 14.73	\$ 18.02	\$ 4.58	\$ 7.23	\$ —
Nine Months Ended September 30, 2016					
DD&A Expense	\$ 1,815	\$ 1,599	\$ 62	\$ 150	\$ 4
Unit Rate per BOE ⁽¹⁾	\$ 15.93	\$ 19.17	\$ 4.74	\$ 8.60	\$ —

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

Total DD&A expense for third quarter and the first nine months of 2017 decreased as compared with 2016 due to the following:

- lower sales volumes in the DJ Basin and the impact of certain property divestitures in second quarter 2016;
- Marcellus Shale upstream divestiture in second quarter 2017, which reduced DD&A expense by \$101 million in third quarter and \$201 million during the first nine months of 2017;
- sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016, which reduced DD&A expense by approximately \$2 million and \$6 million, in third quarter and first nine months of 2017, respectively;
- a reduction in depletable costs of \$153 million in the second quarter 2017 due to the reallocation of common asset costs from Alen, offshore Equatorial Guinea, to the West Africa natural gas monetization development project, which reduced DD&A expense by \$26 million in the first nine months of 2017; and
- lower sales volumes in Gulf of Mexico due to natural field decline and reduction in the depletable costs due to downward revisions in estimates of asset retirement costs;

partially offset by:

- higher sales volumes of 17 MBoe/d in the Delaware Basin during third quarter 2017, including 8 MBoe/d attributable to increased development and enhanced well design and completion techniques and 9 MBoe/d contributed by recently acquired Clayton Williams Energy assets;
- an increase in sales volumes from the Gunflint development, Gulf of Mexico, which commenced production in July 2016; and
- higher sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The unit rate per BOE for third quarter 2017, as compared with 2016, was relatively flat. Overall, the unit rate decreased primarily due to the reduction in Alen net book value in second quarter 2017 and certain DJ Basin property divestitures since third quarter 2016. These decreases were offset by the commencement of sales volumes from new crude oil-focused wells in US onshore, as well as, the divestiture of natural gas-focused sales volumes from Marcellus Shale upstream assets.

The decrease in the unit rate per BOE for the first nine months of 2017, as compared with 2016, was primarily due to the divestiture of certain assets in the DJ Basin, an increase in natural gas sales volumes from the Tamar field, and the reduction in Alen net book value, partially offset by the divestiture of natural gas-focused sales volumes from Marcellus Shale upstream assets and the commencement of sales volumes from new crude oil-focused wells in US onshore.

Other Operating Expense, Net See [Item 1. Financial Statements – Note 2. Basis of Presentation](#) and [Item 1. Financial Statements – Note 11. Segment Information](#) for discussion of other operating expense items for third quarter and first nine months of 2017 as compared with 2016.

Loss (Gain) 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; and (ii) non-cash (increases) or decreases in the fair values of our crude oil and natural gas commodity derivative contracts.

For the first nine months of 2017, gain on commodity derivative instruments included:

- net cash settlement receipts of \$18 million; and

Table of Contents

- non-cash increases in the fair value of our derivative instruments of \$127 million primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

For the first nine months of 2016, loss on commodity derivative instruments included:

- net cash settlement receipts of \$454 million; and
- non-cash decreases in the fair value of our derivative instruments of \$507 million primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

See [Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities](#) and [Note 7. Fair Value Measurements and Disclosures](#).

MIDSTREAM

The Midstream segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

Noble Midstream Segment – Major Midstream Project Updates

Third-Party Sales During third quarter 2017, we began providing crude oil and produced water gathering services to an unaffiliated third party in the Greeley Crescent integrated development plan (IDP) area of the DJ Basin, in addition to the fresh water delivery services we began providing in second quarter 2017.

Major Midstream Construction Projects During third quarter 2017, we progressed the construction and development of multiple major projects including:

- completion of construction of our crude oil and produced water gathering systems servicing the Greeley Crescent IDP area of the DJ Basin;
- completion of the connection from the central gathering facility (CGF) in the Delaware Basin to the Advantage pipeline allowing crude oil to flow from the completed facility to the Advantage pipeline in late August 2017;
- continued construction activities on the expansion of a freshwater system servicing the Mustang IDP area of the DJ Basin and commencement of construction of the backbone gathering infrastructure build-out, which is expected to be completed in early 2018; and
- commencement of the construction of a second CGF in the Delaware Basin which is expected to be online by the end of 2017.

Results of Operations

Highlights for our Midstream segment were as follows:

Third Quarter 2017 Significant Midstream Operating Highlights Included:

- completion of our first CGF and crude oil, natural gas and produced water gathering infrastructure located in the Delaware Basin of Texas along with tie-in to the Advantage pipeline; and
- commencement of crude oil, natural gas and produced water gathering services to a third party in the DJ Basin.

Third Quarter 2017 Midstream Financial Results Included:

- pre-tax income of \$58 million, as compared with pre-tax income of \$47 million for third quarter 2016; and
- capital expenditures, excluding acquisitions, of \$96 million compared with \$9 million capital expenditures for third quarter 2016.

Following is a summarized statement of operations for our Midstream segment:

<i>(millions)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Midstream Services Revenues - Third Party	\$ 7	\$ —	\$ 12	\$ —
Income from Equity Method Investees	13	9	41	39
Intersegment Revenues	72	57	198	143
Total Revenues	92	66	251	182
Operating Costs and Expenses	24	14	66	42
Depreciation and Amortization	10	5	20	14
Income Before Income Taxes	58	47	165	126

Table of Contents

The amount of revenue generated by the midstream business depends primarily on the volumes of crude oil, natural gas and water for which services are provided to the E&P business and third party customers. These volumes are affected primarily by the level of drilling and completion activity in the areas of upstream operations and by changes in the supply of, and demand for, crude oil, natural gas and NGLs in the markets served directly or indirectly by our midstream assets.

Total revenues for the three and nine months ended September 30, 2017 increased from 2016 due to the following:

- an increase of \$15 million and \$55 million, respectively, driven by drilling and completion activity in the Wells Ranch and East Pony IDP areas of the DJ Basin coupled with expansion and gathering system growth which resulted in increased services related to fresh water delivery, water logistics, and additional crude oil and natural gas gathering services;
- an increase of \$7 million and \$12 million, respectively, due to the commencement of fresh water deliveries and crude oil, natural gas and produced water gathering services provided to a third party in the DJ Basin; and
- an increase of \$4 million and \$2 million, respectively, in income from Cone Gathering LLC and Cone Midstream Partners LP as well as income received from Advantage Pipeline LLC.

Total operating expenses for the three and nine months ended September 30, 2017 increased from 2016 by \$12 million and \$24 million, respectively, due to the following:

- an increase due to higher drilling and completion activity in the Wells Ranch and East Pony IDP areas of the DJ Basin which resulted in increased fresh water volumes required and additional water logistic services for produced water; and
- an increase associated with the commencement of crude oil and natural gas gathering services driven by expansion and gathering system growth.

Depreciation and amortization expense for the three and nine months ended September 30, 2017 increased from 2016 by \$5 million and \$6 million, respectively, due to the assets placed in service in the respective periods, specifically assets associated with the construction of the Greeley Crescent facilities and expansion of the Delaware Basin gathering systems.

Results of Operations – Corporate and Other

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
G&A Expense (millions)	\$ 102	\$ 95	\$ 304	\$ 293
Unit Rate per BOE ⁽¹⁾	\$ 3.21	\$ 2.48	\$ 2.98	\$ 2.57

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

G&A expense for the third quarter and first nine months of 2017 increased as compared with 2016 primarily due to increased employee costs driven by acquisition activities. The increase in the unit rate per BOE for the first nine months of 2017 as compared with 2016 was due primarily to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets.

Other Operating Expense, Net See [Item 1. Financial Statements – Note 2. Basis of Presentation](#) and [Item 1. Financial Statements – Note 11. Segment Information](#) for discussion of other operating expense items for the third quarter and first nine months of 2017 as compared with 2016.

Loss (Gain) on Extinguishment of Debt See [Item 1. Financial Statements – Note 6. Debt](#) for discussion of our extinguishment of debt activities for the third quarter and first nine months of 2017 as compared with 2016.

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

<i>(millions, except unit rate)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Interest Expense, Gross	\$ 100	\$ 103	\$ 306	\$ 312
Capitalized Interest	(12)	(17)	(35)	(70)
Interest Expense, Net	\$ 88	\$ 86	\$ 271	\$ 242
Unit Rate per BOE ⁽¹⁾	\$ 2.77	\$ 2.25	\$ 2.66	\$ 2.12

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

Interest expense, gross, for the third quarter and first nine months of 2017 remained relatively flat as compared with 2016. While we engaged in debt refinancing activities in third quarter 2017, interest expense remained consistent for the period and in the future as a result of these activities, we expect future cash interest expense will be lower by approximately \$35 million on an annual basis. See [Item 1. Financial Statements - Note 6. Debt](#).

The decrease in capitalized interest for the third quarter and first nine months of 2017 as compared with 2016 is primarily due to lower work in progress amounts related to major long-term projects including Gunflint, Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, which were both completed in July 2016. We also impaired certain of our discoveries offshore Equatorial Guinea after an additional review of 3D seismic data was completed in fourth quarter 2016, resulting in a lower capitalized exploratory well cost balance. See [Item 1. Financial Statements - Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs](#).

The increase in the unit rate of interest expense, net, per BOE was due to the changes noted above, combined with the decrease in total sales volumes.

Income Taxes See [Item 1. Financial Statements – Note 10. Income Taxes](#) for a discussion of the change in our effective tax rate for the third quarter and first nine months of 2017 as compared with 2016.

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 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 periodically capitalize on financially attractive merger and acquisition opportunities, such as the recent Clayton Williams Energy Acquisition. We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives.

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 property divestitures. 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. We also evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending.

In 2017, we engaged in significant development and portfolio activities which has required an intensive capital program. We strive to fund our capital program through organic cash flows and when needed, utilize borrowings under our Revolving Credit Facility. In third quarter 2017, we borrowed under our Revolving Credit Facility and had outstanding \$275 million as of September 30, 2017. Funds were utilized for general corporate purposes and for funding of our capital development program.

We continue to undertake proactive and strategic actions to maintain liquidity and a strong balance sheet. During third quarter 2017, for example, we took steps in managing our long-term debt maturities and liquidity. We issued \$600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and \$500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. We used the proceeds to repurchase \$1 billion of our 8.25% senior unsecured notes which were due March 1, 2019. Through these transactions we effectively enhanced our financial flexibility and lowered our future cash interest expense by approximately \$35 million on an annual basis. As a result, we ended third quarter 2017 with over \$4 billion in liquidity, including \$3.7 billion of availability under our Revolving Credit Facility.

During second quarter 2017, Noble Midstream Partners purchased additional midstream assets from Noble Energy for \$270 million and expanded its business through entry into a joint venture. Funding for these transactions included a \$138 million private placement of common units and \$90 million of net borrowings under the Noble Midstream Services Revolving Credit Facility. As of September 30, 2017, \$200 million was outstanding under the Noble Midstream Services Revolving Credit Facility. Funds were used to partially fund the second quarter 2017 acquisitions and to finance the midstream capital program. See [Note 4. Acquisitions and Divestitures](#).

Also, during the first nine months of 2017, we received \$300 million in payments from foreign operations on an outstanding note payable, leaving a balance of approximately \$430 million that can be repaid without additional US tax impact.

As of September 30, 2017, our outstanding debt (excluding capital lease obligations) totaled \$7.3 billion. While we have no near-term debt maturities, we may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness.

Table of Contents

We may from time to time seek to retire or purchase our outstanding senior notes through cash purchases in open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Available Liquidity

Information regarding cash and debt balances is shown in the table below:

<i>(millions, except percentages)</i>	September 30, 2017	December 31, 2016
Total Cash ⁽¹⁾	\$ 564	\$ 1,209
Amount Available to be Borrowed Under Revolving Credit Facility ⁽²⁾	3,725	4,000
Total Liquidity	\$ 4,289	\$ 5,209
Total Debt ⁽³⁾	\$ 7,604	\$ 7,114
Noble Energy Share of Equity	9,466	9,288
Ratio of Debt-to-Book Capital ⁽⁴⁾	45%	43%

⁽¹⁾ As of September 30, 2017, total cash included cash and cash equivalents of \$11 million related to Noble Midstream Partners. As of December 31, 2016, total cash included cash and cash equivalents of \$57 million related to Noble Midstream Partners and restricted cash of \$30 million related to a Delaware Basin property acquisition that closed in January 2017.

⁽²⁾ Excludes \$150 million and \$625 million available to be borrowed under the Noble Midstream Services Revolving Credit Facility and Leviathan Term Loan Facility, respectively, which are not available to Noble Energy for general corporate purposes. See discussion below.

⁽³⁾ Total debt includes capital lease obligations and excludes unamortized debt discount/premium. See [Item 1. Financial Statements – Note 6. Debt](#).

⁽⁴⁾ 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 \$564 million in cash and cash equivalents at September 30, 2017, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately \$425 million of this cash is attributable to our foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings of \$324 million for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credits. Our cash and cash equivalents at September 30, 2017 included \$11 million relating to Noble Midstream Partners.

Revolving Credit Facility Noble Energy's Revolving Credit Facility matures on August 27, 2020, and the commitment is \$4 billion through the maturity date. On April 24, 2017, we borrowed \$1.3 billion to fund activities in connection with the Clayton Williams Energy Acquisition, including the cash portion of the acquisition consideration, redeem outstanding debt, pay associated make-whole premiums and pay related fees and expenses. We repaid all outstanding borrowings during second quarter 2017 with proceeds received from the Marcellus Shale upstream divestiture, cash on hand, and cash proceeds received from the Noble Midstream Partners asset contribution. In third quarter 2017, we borrowed and had outstanding \$275 million as of September 30, 2017 under our Revolving Credit Facility which was utilized for general corporate purposes and for funding of our capital development program. See [Item 1. Financial Statements - Note 3. Clayton Williams Energy Acquisition](#) and [Note 4. Acquisitions and Divestitures](#).

Noble Midstream Services Revolving Credit Facility Noble Midstream Services Revolving Credit Facility matures on September 20, 2021, and the commitment is \$350 million through the maturity date. As of September 30, 2017, \$200 million was outstanding under this facility which was used to partially fund second quarter 2017 acquisitions and to finance the midstream capital program. See [Note 4. Acquisitions and Divestitures](#). During October 2017, an additional \$25 million was borrowed under this facility to fund midstream construction activities.

Leviathan Term Loan Facility On February 24, 2017, we entered into a facility agreement (Leviathan Term Loan Facility) providing for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to \$1.0 billion, of which \$625 million is initially committed. Any amounts borrowed under the Leviathan Term Loan Facility will be available to fund a portion of our share of costs for the initial phase of development of the Leviathan field, offshore Israel. To support the Leviathan development program and to bring first production online by the end of 2019, we may borrow amounts under this facility in the near-term. As of September 30, 2017, no amounts were drawn under this facility.

Senior Notes On August 15, 2017, we issued \$600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and \$500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. Interest on the 3.85% senior notes and 4.95% senior notes is payable semi-annually beginning January 15, 2018, and February 15, 2018, respectively. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. The senior

[Table of Contents](#)

notes were issued at a discount of \$4 million and debt issuance costs incurred totaled \$11 million. These amounts are reflected as a reduction of long-term debt and are amortized over the life of the facility. Proceeds of \$1.1 billion from the issuance of senior notes were used solely to fund the tender offer and the redemption of \$1 billion of our 8.25% senior notes due March 1, 2019.

Interest Rate Risk Certain of our borrowings subject us to interest rate risk. See [Item 1. Financial Statements – Note 6. Debt](#) and [Item 3. Quantitative and Qualitative Disclosures About Market Risk](#).

Contractual Obligations

The following table summarizes certain contractual obligations as of September 30, 2017 that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. Unless otherwise noted, the table excludes amounts related to Noble Midstream Partners, and all amounts shown are net to our interest. For additional information, see the Notes to the Consolidated Financial Statements under Item 1. Financial Statements of this Form 10-Q.

Obligation	Note Reference	Total	October - December 2017	2018 and 2019	2020 and 2021	2022 and beyond
<i>(millions)</i>						
Long-Term Debt ⁽¹⁾	Note 6	\$ 6,839	\$ —	\$ 550	\$ 1,379	\$ 4,910
Interest Payments ⁽²⁾	Note 6	5,884	83	648	619	4,534
Capital Lease Obligations ⁽³⁾	Note 6	355	20	119	71	145
Drilling and Equipment Obligations ⁽⁴⁾	Note 12	510	105	405	—	—
Purchase Obligations ⁽⁵⁾	Note 12	268	31	168	33	36
Transportation and Gathering ⁽⁶⁾	Note 12	2,537	53	523	462	1,499
Operating Lease Obligations ⁽⁷⁾	Note 12	340	12	75	64	189
Other Liabilities ⁽⁸⁾						
Asset Retirement Obligations ⁽⁹⁾	Note 9	944	30	231	63	620
Total Contractual Obligations		\$ 17,677	\$ 334	\$ 2,719	\$ 2,691	\$ 11,933

(1) Long-term debt excludes balances outstanding under the revolving credit facilities and capital lease obligations.

(2) Interest payments are based on the total debt balance, excluding balances outstanding under the revolving credit facilities, scheduled maturities and interest rates in effect at September 30, 2017.

(3) Annual capital lease payments, net to our interest, exclude regular maintenance and operational costs.

(4) Drilling and equipment obligations represent our working interest share of contractual agreements with third-party service providers to procure drilling rigs and other related equipment for exploratory and development drilling activities.

(5) Purchase obligations represent our working interest share of contractual agreements to purchase goods or services that are enforceable, are legally binding and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction.

(6) Transportation and gathering obligations represent minimum charges for firm transportation and gathering agreements associated with production.

(7) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. Amounts have not been discounted.

(8) The table excludes deferred compensation liabilities of \$216 million as specific payment dates are unknown.

(9) Asset retirement obligations are discounted.

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 and/or penalty payments.

Leviathan Development Obligations The initial development of our Leviathan field requires substantial infrastructure and capital. We have executed major equipment and installation contracts in support of our development activities. As of September 30, 2017, we had entered into approximately \$534 million, net, of contracts to support development and bring first production online by the end of 2019.

Continuous Development Obligations Although the majority of our assets are held by production, certain of our US onshore assets are held through continuous development obligations. As such, we plan our activities and budget accordingly to ensure that we meet any such obligations that are in line with our strategic plans. Therefore, we are contractually obligated to fund a level of development activity in these areas.

Table of Contents

Marcellus Shale Firm Transportation Agreements In connection with the Marcellus Shale upstream divestiture, we reduced our firm transportation financial commitments through transfer of several contracts to the acquirer.

We retained certain other firm transportation contracts representing a total financial commitment of approximately \$1.6 billion, undiscounted, primarily with remaining contract terms of 15 years.

One of the retained contracts, related to Texas Eastern pipeline, will be fully utilized through an agreement with the acquirer, whereby the acquirer will deliver quantities of natural gas to us and receive a netback sales price that reflects the value received by us at the sales point, less our effective fixed transportation fees and other expenses, plus a margin. This contract represents an undiscounted financial commitment of approximately \$119 million as of September 30, 2017, before offset by the netback agreement, thus reducing the remaining overall commitment noted above.

Two of the retained contracts relate to the Leach & Rayne Xpress projects, which are currently under construction and targeted to be placed in service mid-to-late fourth quarter 2017. These contracts represent an undiscounted financial commitment of approximately \$627 million. We are in negotiations with third parties for the permanent assignment or release of a portion of our capacity under these contracts which would reduce our undiscounted financial commitment. At this time, we are unable to predict with certainty the outcome of our commercialization activities, our ability to utilize retained capacity and the timing of when we may recognize a non-cash exit cost in line with accounting for exit costs associated with these two pipeline projects.

Two additional retained contracts relate to the NEXUS and WB Xpress projects. The NEXUS project received approval from the FERC in third quarter 2017, construction commenced in late 2017 and the project is scheduled to be placed in service fourth quarter 2018. The WB Xpress project, while also scheduled to be placed in service fourth quarter 2018, has not yet been approved by the FERC, and construction has not begun. These contracts represent an undiscounted financial commitment of approximately \$869 million.

We are currently engaged in actions to commercialize and address these remaining commitments, which provide for the transportation of approximately 500,000 MMBtu/day of natural gas. Actions include the permanent assignment of capacity, negotiation of capacity release, utilization of capacity through purchase of third party natural gas, and other potential arrangements. In addition, we have a "call" or right to purchase natural gas, priced at a regional index, from the acquirer of the Marcellus Shale upstream assets. This call extends through July 1, 2022 and may be exercised on quantities of the acquirer's production between 431,100 MMBtu/d and 832,645 MMBtu/d.

We expect these actions, some of which may require pipeline and/or FERC approval, to ultimately reduce the financial commitment associated with these contracts. At the date each pipeline is placed in service and our commitment begins, we will evaluate our position. If we determine that we will not utilize a portion, or all, of the contracted pipeline capacity, we will accrue a liability, at fair value, for the net amount of the estimated remaining financial commitment and include the related expense in operating expense in our consolidated statements of operations.

In accordance with US GAAP, we recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. As a result, in second quarter 2017, we accrued non-cash exit costs of \$41 million, discounted, relating to our transportation contract with the Gateway pipeline project. Gateway is currently in service; however, we no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. As such, we recorded a charge to expense which is included in loss on Marcellus Shale upstream divestiture in our consolidated statements of operations.

See [Item 1. Financial Statements – Note 12. Commitments and Contingencies](#).

Certain of these contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under the commitments. As properties are undergoing development activities, we may experience temporary shortfalls until production volumes increase to meet or exceed the minimum volume commitments.

For the first nine months of both 2017 and 2016, we incurred expense of \$39 million, related to volume deficiencies and/or unutilized commitments primarily in our US onshore operations. These amounts are recorded as marketing expense in our consolidated statements of operations. We expect to continue to incur expense related to deficiency and/or unutilized commitments in the near-term. Should commodity prices 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. 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.

Cash Flows

Summary cash flow information is as follows:

(millions)	Nine Months Ended September 30,			
	2017		2016	
Total Cash Provided By (Used in)				
Operating Activities	\$	1,418	\$	1,054
Investing Activities		(1,810)		(386)
Financing Activities		(224)		123
(Decrease) Increase in Cash and Cash Equivalents	\$	(616)	\$	791

Operating Activities Net cash provided by operating activities for the first nine months of 2017 increased as compared with 2016. The change in cash flows from operating activities was primarily the result of higher average realized commodity prices partially offset by lower sales volumes. Working capital changes resulted in a \$27 million operating cash flow decrease for the first nine months of 2017, as compared with a \$171 million operating cash flow decrease for the first nine months of 2016. The changes in working capital were primarily due to an increase in our current liabilities, including accrued liabilities and trade payables for drilling and development costs and midstream capital expenditures. The increase in current liabilities was partially offset by the increase in accounts receivable resulting from higher revenues and higher joint interest billing receivables primarily due to billings associated with Leviathan development project costs.

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.

The following presents our capital expenditures (on an accrual basis) for the three and nine months ended September 30, 2017 and 2016:

(millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition ⁽¹⁾	\$ (10)	\$ —	\$ 1,816	\$ —
Proved Property Acquisition ⁽²⁾	(2)	—	839	—
Exploration	15	25	32	183
Development	570	223	1,751	657
Midstream ⁽³⁾	96	9	342	29
Corporate and Other	11	38	24	58
Total	\$ 680	\$ 295	\$ 4,804	\$ 927
Investment in Equity Method Investee ⁽⁴⁾	\$ —	\$ 2	\$ 68	\$ 8
Increase in Capital Lease Obligations	\$ —	\$ 5	\$ —	\$ 5

⁽¹⁾ Unproved property acquisition cost for the three months ended September 30, 2017 includes purchase price adjustments related to the Clayton Williams Energy Acquisition. Unproved property acquisition cost for the first nine months of 2017 includes \$1.6 billion related to the Clayton Williams Energy Acquisition and \$246 million related to the Delaware Basin asset acquisition.

⁽²⁾ Proved property acquisition cost for the three months ended September 30, 2017 includes purchase price adjustments related to the Clayton Williams Energy Acquisition. Proved property acquisition cost for the first nine months of 2017 includes \$722 million of proved properties and \$58 million of asset retirement obligations acquired in the Clayton Williams Energy Acquisition and \$58 million related to the Delaware Basin asset acquisition.

⁽³⁾ Midstream expenditures for the first nine months of 2017 include gathering and processing assets related to the Clayton Williams Energy Acquisition.

⁽⁴⁾ Investment in equity method investee for the first nine months of 2017 represents our contribution to the Advantage Joint Venture, in which Noble Midstream Partners owns a 50% interest.

Capital spending for additions to property, plant and equipment increased by \$792 million during the first nine months of 2017 as compared with the first nine months of 2016, primarily due to increased US onshore development activity in response to a more favorable commodity price environment, and included \$258 million related to the initial Leviathan project development.

[Table of Contents](#)

In addition, we used \$637 million of cash, net of \$21 million of cash acquired through the Clayton Williams Acquisition, to fund a portion of the consideration paid in the Clayton Williams Energy Acquisition, and we acquired Delaware Basin and other assets for \$327 million. We received net cash proceeds of \$1.0 billion from the Marcellus Shale upstream divestiture, and other investing activities provided a net \$61 million of cash.

In comparison, during the first nine months of 2016, we received net proceeds of \$786 million from asset sales.

Financing Activities Our financing activities include the issuance or repurchase of Noble Energy common stock and Noble Midstream Partners common units, payment of cash dividends to Noble Energy shareholders and cash distributions to Noble Midstream Partners noncontrolling interest owners, and debt transactions.

Our primary financing activities during the first nine months of 2017 included \$275 million net Revolving Credit Facility borrowings (including the borrowing and repayment of \$1.3 billion associated with the Clayton Williams Energy Acquisition), \$200 million net Noble Midstream Services Revolving Credit Facility borrowings used primarily to fund an acquisition, a \$1.1 billion senior note refinancing, and \$595 million related to the repayment of Clayton Williams Energy debt. In addition, we received \$138 million net proceeds from the issuance of Noble Midstream Partners common units, paid \$141 million of cash dividends and \$19 million of cash distributions, and made \$44 million of capital lease principal payments.

During the first nine months of 2017, we received \$9 million cash proceeds from the exercise of stock options. We also purchased 1,010,078 shares of treasury stock with a value of \$36 million. These shares included 719,849 shares with a value of \$25 million related to vesting of Clayton Williams Energy restricted stock and options in connection with the Clayton Williams Energy Acquisition. The remaining shares were surrendered for the payment of withholding taxes due on the vesting of employee restricted stock awards.

In comparison, during the first nine months of 2016, we drew \$1.4 billion under our Term Loan Facility and received \$299 million proceeds from the Noble Midstream Partners initial public offering. We paid \$129 million of cash dividends, repurchased senior notes for \$1.38 billion, and made \$39 million of capital lease principal payments. We also received \$8 million cash proceeds from the exercise of stock options and purchased 235,157 shares of treasury stock from employees with a value of \$8 million for the payment of withholding taxes.

See [Item 1. Financial Statements – Consolidated Statements of Cash Flows](#).

Dividends On October 24, 2017, our Board of Directors declared a quarterly cash dividend of 10 cents per common share, which will be paid on November 20, 2017 to shareholders of record on November 6, 2017. 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, UPDATE

The following discussion updates the policies and estimates disclosed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates of our Annual Report on Form 10-K for the year ended December 31, 2016.

Goodwill

As of September 30, 2017, our consolidated balance sheet includes goodwill of \$1.3 billion, which resulted from the excess of the purchase price over amounts assigned to assets acquired and liabilities assumed in the Clayton Williams Energy Acquisition in second quarter 2017. All of our recorded goodwill is assigned to the Texas reporting unit.

Annual Goodwill Test Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. Our policy is to conduct a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions; industry and market conditions, including commodity prices; cost factors; overall financial performance; reporting unit dispositions and acquisitions; and other relevant entity-specific events.

If, after assessing the totality of events or circumstances described above, we determine that it is more likely than not that the fair value of our Texas reporting unit is less than its carrying amount, the two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If, after performing the two-step goodwill test, it is determined that the carrying value of goodwill is impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired.

The two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill is not considered to be impaired, and the second step of the test is not required. If necessary, the second step of the impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

Goodwill Impairment Test - Estimates and Assumptions

The first step of the impairment test requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. If it is necessary to determine the fair value of the Texas reporting unit, we use a combination of the income approach and the market approach.

Under the income approach, the fair value of the Texas reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs and proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods.

Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil, natural gas and NGL reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer group based weighted average cost of capital.

Under the market approach, we estimate the fair value of the Texas reporting unit by comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments about the selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums, thereby creating a group of guideline public companies or transactions, or a peer group, that are engaged in similar operations with comparable risks and returns as our reporting unit. We use the peer group multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics. We use earnings before interest, taxes, DD&A and exploration expense (also known as EBITDAX) as our financial metric as we believe it more accurately compares companies using successful efforts and full cost accounting methods, both of which are in our peer group.

Goodwill Impairment Review - Conclusion

Based on the results of our impairment test, we concluded that our goodwill at September 30, 2017 was not impaired, because the fair value of our Texas reporting unit was in excess of its respective net book value, including goodwill, by approximately 6%. While not required under Accounting Standards Codification ("ASC") 350 "Intangibles - Goodwill and Other", we also

performed a reconciliation of the determined enterprise fair value as compared to our total company market capitalization. From this additional analysis, we have concluded that the determination of the enterprise fair value closely aligns with our market capitalization.

We will continue to perform our annual impairment test at the end of the third quarter of each year unless events or circumstances trigger the need for an interim impairment test. The estimates used in our goodwill impairment test do not constitute forecasts or projections of future results of operations, but are rather estimates and assumptions based on historical results and assessments of macroeconomic factors affecting the Texas reporting unit as of the valuation date. We believe that our estimates and assumptions are reasonable, but they are subject to change from period to period. Actual results of operations and other factors will likely differ from the estimates used in our discounted cash flow valuation and it is possible that differences could be material. Although we base the fair value estimate of the Texas reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In the event of a prolonged industry downturn, commodity prices may stay depressed or decline further, thereby causing the fair value of the Texas reporting unit to decline, which could result in an impairment of goodwill.

Disposals If, in the future, we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we will include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount will be based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. [See Item 1. Financial Statements - Note 3. Clayton Williams Energy Acquisition.](#)

Exit Costs

During second quarter 2017, in connection with our Marcellus Shale upstream divestiture, we accrued a liability of \$41 million, discounted, for exit costs related to our commitment under a retained firm transportation contract, and charged the amount to loss on Marcellus Shale upstream divestiture in our consolidated statements of operations.

We have retained additional Marcellus Shale firm transportation contracts, relating to pipeline projects which are not yet commercially available to us. These projects are either under construction or have not yet been approved by the FERC. We did not accrue any exit cost liabilities related to these contracts as of June 30, 2017 or September 30, 2017. See [Item 1. Financial Statements – Note 12. Commitments and Contingencies.](#)

We account for exit costs in accordance with ASC 420 – *Exit or Disposal Cost Obligations*, which requires that a liability for a cost associated with an exit or disposal activity be recognized at fair value in the period in which the liability is incurred. Further, a liability for costs that will continue to be incurred under a contract for its remaining term without economic benefit to the entity shall be recognized at the “cease-use date”, which is defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services.

As these projects become commercially available to us, our management must make significant judgments and estimates regarding the timing and amount of recognition of any additional exit cost liabilities, taking into consideration our commercialization activities and/or the potential occurrence of a cease-use date.

Any additional exit cost liability will be initially recorded at fair value, and, in periods subsequent to initial measurement, changes to the liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, will be recognized as an adjustment to the liability in the period of the change. Therefore, initial recognition of a liability, as well as subsequent increases or decreases in exit cost liability estimates, could have a significant impact on our consolidated net income (loss).

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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. See [Results of Operations - Revenues](#), above.

Derivative Instruments Held for Non-Trading Purposes 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, 2017, 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 \$6 million. Based on the September 30, 2017 published commodity futures price curves for the underlying commodities, a hypothetical price increase of 10% per Bbl for crude oil and 10% per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately \$44 million, effectively changing our net asset position to a net liability of \$38 million. Our derivative instruments are executed

under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See [Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities](#).

Marcellus Shale Firm Transportation Contracts We retained certain other firm transportation contracts after the closing of the Marcellus Shale upstream divestiture. These contracts generally relate to pipelines which are currently under construction and not available for use, or pipelines for which construction has not yet begun and which are not currently approved by the FERC. Our volume commitments under these contracts total approximately 500,000 MMBtu/d.

Access to these contracts may be operationally or financially beneficial to other natural gas operators in the region. We are currently assessing various options to commercialize and address the remaining commitments, including the negotiation of capacity release, utilization of capacity through the purchase of third party natural gas and other potential arrangements. In addition, we have a “call” or right to purchase natural gas priced at a regional index from the acquirer of the Marcellus Shale upstream assets through July 1, 2022 when the acquirer's production exceeds 431,100 MMBtu/d but is less than 832,645 MMBtu/d. However, we do not have information regarding the acquirer's future development plans; therefore, there is uncertainty regarding when or if any volumes may become available. We expect these actions, some of which may require pipeline and/or FERC approval, to ultimately reduce the financial commitment associated with these contracts.

Changes in natural gas prices, in and out of basin supply and demand, the industry's ability to export substantial natural gas volumes to areas outside of the Marcellus Shale, as well as changes in basis differentials, could impact our commercialization options. We have no control over these market factors and therefore may not realize any benefits from our commercialization efforts. As a result, and when or if required, we may recognize substantial future liabilities, at fair value, for the net amount of the estimated remaining commitments under these contracts and charges to other operating expense in future periods. See [Item 1. Financial Statements – Note 12. Commitments and Contingencies](#).

Interest Rate Risk

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

At September 30, 2017, we had approximately \$7.3 billion (excluding capital lease obligations) of long-term debt outstanding, net of unamortized discount, premium and debt issuance costs. Of this amount, \$6.2 billion was fixed-rate debt, net of unamortized discount, premium and debt issuance costs, with a weighted average interest rate of 5.05%. 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, 2017, our cash and cash equivalents totaled \$564 million, approximately 59% of which was invested in money market funds and short-term investments with major financial institutions.

In addition, borrowings under the Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility and 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, 2017, 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, Term Loan Facility or the amounts currently outstanding under the Noble Revolving Credit Facility or Noble Midstream Services Revolving Credit Facility 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, 2017 and 2016.

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 future results of operations;
- our liquidity and ability to finance our exploration, development and acquisitions activities;
- our ability to satisfy contractual commitments, including utilization or commercialization of firm transportation commitments in the Marcellus Shale;
- our ability to make and integrate acquisitions;
- our ability to successfully and economically explore for and develop crude oil, natural gas and NGL resources;
- anticipated trends in our business;
- market conditions in the oil and gas industry;
- the impact of governmental fiscal regulation, including federal, state, local, and foreign host regulations, and/or terms, such as those involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

Any such projections or statements reflect Noble Energy's views (as of the date such projects were published or such statements were made) about future events and financial performance. No assurances can be given that such events or performance will occur as projected, and actual results may differ materially from those projected. Important factors that could cause the actual results to differ materially from those projected include, without limitation, the volatility in commodity prices for crude oil and natural gas, the presence or recoverability of estimated reserves, the ability to replace reserves, environmental risks, drilling and operating risks, exploration and development risks, competition, government regulation or other action, the ability of management to execute its plans to meet its goals and other risks inherent in Noble Energy's business that are detailed in its Securities and Exchange Commission filings.

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, 2016 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, 2016 is available on our website at www.nbleenergy.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 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. These forms can also be obtained from the SEC by calling 1-800-SEC-0330. Alternatively, you may access these reports at the SEC's website at www.sec.gov.

Part II. Other Information

Item 1. Legal Proceedings

See discussion of legal proceedings in [Part I. Financial Information, Item 1. Financial Statements - Note 12. 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, 2016.

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, 2016.

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)
7/1/2017 - 7/31/2017	5,208	\$ 28.65	—	—
8/1/2017 - 8/31/2017	16,908	23.78	—	—
9/1/2017 - 9/30/2017	1,568	26.87	—	—
Total	23,684	\$ 25.05	—	—

⁽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.

Table of Contents

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

<u>Exhibit Number</u>	<u>Exhibit**</u>
2.1	<u>Agreement and Plan of Merger, dated as of January 13, 2017, by and among Noble Energy, Inc., Wild West Merger Sub Inc., NBL Permian LLC, and Clayton Williams Energy, Inc. (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed on January 17, 2017 and incorporated herein by reference).</u>
2.2	<u>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).</u>
2.3	<u>Exchange Agreement, executed October 29, 2016, by and between CNX Gas Company LLC and Noble Energy, Inc. (filed as Exhibit 2.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 and incorporated herein by reference).</u>
2.4	<u>Purchase and Sale Agreement among Noble Energy, Inc. and HG Energy II Appalachia, LLC dated May 1, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 1, 2017) filed on May 5, 2017 and incorporated herein by reference).</u>
2.5	<u>Purchase Agreement by and among Wheeling Creek Midstream, LLC, Noble Energy US Holdings, LLC and Noble Energy, Inc. dated May 17, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 17, 2017) filed on May 23, 2017 and incorporated herein by reference).</u>
3.1	<u>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).</u>
3.2	<u>By-Laws of Noble Energy, Inc. (as amended through January 24, 2017) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 23, 2017) filed on January 27, 2017 and incorporated herein by reference).</u>
3.3	<u>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).</u>
3.4	<u>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).</u>
4.1	<u>Seventh Supplemental Indenture dated as of August 15, 2017, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: August 15, 2017) filed on August 15, 2017 and incorporated herein by reference).</u>
12.1	<u>Calculation of ratio of earnings to fixed charges, filed herewith.</u>
31.1	<u>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.</u>
31.2	<u>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.</u>
32.1	<u>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.</u>
32.2	<u>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.</u>
101.INS	XBRL Instance Document

Table of Contents

101.CAL XBRL Calculation Linkbase Document

101.LAB XBRL Label Linkbase Document

101.PRE XBRL Presentation Linkbase Document

101.DEF XBRL Definition Linkbase Document

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Executive Vice President and Chief Financial Officer, Noble Energy, Inc., 1001 Noble Energy Way, Houston, Texas 77070.

Signatures

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

NOBLE ENERGY, INC.
(Registrant)

Date October 31, 2017

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

Noble Energy, Inc.
Calculation of Ratio of Earnings to Fixed Charges

	Nine Months Ended September 30,			Year Ended December 31,		
	2017	2016	2015	2014	2013	2012
<i>(millions)</i>						
(Loss) Income From Continuing Operations Before Income Tax, Non-controlling Interests and Income From Equity Investees	\$ (2,654)	\$ (1,887)	\$ (2,309)	\$ 1,540	\$ 1,138	\$ 1,170
Add (Deduct)						
Fixed Charges	323	440	435	349	296	288
Capitalized Interest	(35)	(84)	(144)	(116)	(121)	(151)
Distributed Income From Equity Investees	60	83	77	226	204	204
(Loss) Earnings as Defined	\$ (2,306)	\$ (1,448)	\$ (1,941)	\$ 1,999	\$ 1,517	\$ 1,511
Net Interest Expense	271	328	263	210	158	125
Capitalized Interest	35	84	144	116	121	151
Interest Portion of Rental Expense	17	28	28	23	17	12
Fixed Charges as Defined	\$ 323	\$ 440	\$ 435	\$ 349	\$ 296	\$ 288
Ratio of Earnings to Fixed Charges	—	—	—	5.7	5.1	5.2
Amount by Which Earnings Were Insufficient to Cover Fixed Charges	\$ 2,629	\$ 1,888	\$ 2,376	\$ —	\$ —	\$ —

**Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)**

I, David L. Stover, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Noble Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ David L. Stover

David L. Stover
Chief Executive Officer

**Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)**

I, Kenneth M. Fisher, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Noble Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Kenneth M. Fisher
Kenneth M. Fisher
Chief Financial Officer

**Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 1350)**

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the "Company") on Form 10-Q for the period ended September 30, 2017 (the "Report"), I, David L. Stover, Chief Executive Officer of the Company, hereby certify that to my knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: October 31, 2017

/s/ David L. Stover

David L. Stover
Chief Executive Officer

**Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 1350)**

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the "Company") on Form 10-Q for the period ended September 30, 2017 (the "Report"), I, Kenneth M. Fisher, Chief Financial Officer of the Company, hereby certify that to my knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: October 31, 2017

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer

