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, 2018

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 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 ☐

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, 2018, there were 479,799,000 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues				
Oil, NGL and Gas Sales	$ 1,136	$ 907	$ 3,409	$ 2,918
Sales of Purchased Oil and Gas and Other	137	53	380	137
Total	1,273	960	3,789	3,055
Costs and Expenses				
Production Expense	273	280	886	866
Exploration Expense	25	64	89	136
Depreciation, Depletion and Amortization	485	523	1,418	1,554
Loss on Marcellus Shale Exit Activities	—	4	—	2,326
Gain on Divestitures, Net	(193)	—	(859)	—
Asset Impairments	—	—	168	—
General and Administrative	107	102	316	304
Other Operating Expense (Income), Net	78	(15)	222	132
Total	775	958	2,240	5,318
Operating Income (Loss)	498	2	1,549	(2,263)
Other (Income) Expense				
Loss (Gain) on Commodity Derivative Instruments	155	22	483	(145)
Interest, Net of Amount Capitalized	70	88	216	271
Other Non-Operating (Income) Expense, Net	(34)	100	(10)	94
Total	191	210	689	220
Income (Loss) Before Income Taxes	307	(208)	860	(2,483)
Income Tax Expense (Benefit)	59	(93)	44	(917)
Net Income (Loss) and Comprehensive Income (Loss) Including Noncontrolling Interests	248	(115)	816	(1,566)
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	21	21	58	46
Net Income (Loss) and Comprehensive Income (Loss) Attributable to Noble Energy	$ 227	$ (136)	$ 758	$ (1,612)
Net Income (Loss) Attributable to Noble Energy per Common Share				
Basic	$ 0.47	$ (0.28)	$ 1.57	$ (3.47)
Diluted	$ 0.47	$ (0.28)	$ 1.56	$ (3.47)
Weighted Average Number of Common Shares Outstanding				
Basic	482	487	484	464
Diluted	484	487	486	464

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

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

	September 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 720	$ 675
Accounts Receivable, Net	698	748
Other Current Assets	309	780
Total Current Assets	1,727	2,203
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	29,029	29,678
Property, Plant and Equipment, Other	893	879
Total Property, Plant and Equipment, Gross	29,922	30,557
Accumulated Depreciation, Depletion and Amortization	(11,677)	(13,055)
Total Property, Plant and Equipment, Net	18,245	17,502
Other Noncurrent Assets	774	461
Goodwill	1,401	1,310
Total Assets	$ 22,147	$ 21,476
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable – Trade	$ 1,239	$ 1,161
Other Current Liabilities	885	578
Total Current Liabilities	2,124	1,739
Long-Term Debt	6,571	6,746
Deferred Income Taxes	983	1,127
Other Noncurrent Liabilities	1,075	1,245
Total Liabilities	10,753	10,857
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; 523 Million and 529 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,249	8,438
Accumulated Other Comprehensive Loss	(27)	(30)
Treasury Stock, at Cost; 39 Million Shares	(731)	(725)
Retained Earnings	2,850	2,248
Noble Energy Share of Equity	10,346	9,936
Noncontrolling Interests	1,048	683
Total Equity	11,394	10,619
Total Liabilities and Equity	$ 22,147	$ 21,476

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,	
	2018	2017
Cash Flows From Operating Activities		
Net Income (Loss) Including Noncontrolling Interests	$ 816	$ (1,566)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,418	1,554
Loss on Marcellus Shale Exit Activities	—	2,326
Gain on Divestitures, Net	(859)	—
Asset Impairments	168	—
Deferred Income Tax Benefit	(150)	(988)
Undeveloped Leasehold Impairment	—	51
(Gain) Loss on Extinguishment of Debt, Net	(3)	98
Loss (Gain) on Commodity Derivative Instruments	483	(145)
Net Cash (Paid) Received in Settlement of Commodity Derivative Instruments	(160)	18
Stock Based Compensation	53	83
Other Adjustments for Noncash Items Included in Income (Loss)	(5)	14
Changes in Operating Assets and Liabilities		
Decrease (Increase) in Accounts Receivable	114	(148)
(Decrease) Increase in Accounts Payable	(91)	230
Increase (Decrease) in Current Income Taxes Payable	54	(41)
Other Current Assets and Liabilities, Net	19	(5)
Other Operating Assets and Liabilities, Net	(81)	(63)
Net Cash Provided by Operating Activities	1,776	1,418
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(2,589)	(1,956)
Proceeds from Sale of 7.5% Interest in Tamar Field	484	—
Proceeds from Sale of CONE Gathering LLC and CNX Midstream Partners Common Units	691	—
Proceeds from Gulf of Mexico Divestiture	383	—
Proceeds from Marcellus Shale Upstream Divestiture	—	1,028
Clayton Williams Energy Acquisition, Net of Cash Received	—	(616)
Saddle Butte Acquisition, Net of Cash Received	(650)	—
Other Acquisitions	(3)	(357)
Proceeds from Other Divestitures	182	129
Additions to Equity Method Investments	—	(68)
Net Cash Used in Investing Activities	(1,502)	(1,840)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(156)	(141)
Purchase and Retirement of Common Stock	(223)	—
Proceeds from Noble Midstream Services Revolving Credit Facility	690	245
Repayment of Noble Midstream Services Revolving Credit Facility	(725)	(45)
Proceeds from Noble Midstream Services Term Loan Credit Facility	500	—
Contributions from Noncontrolling Interest Owners	348	—
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	138
Proceeds from Revolving Credit Facility	1,450	1,585
Repayment of Revolving Credit Facility	(1,680)	(1,310)
Repayment of Clayton Williams Energy Long-term Debt	—	(595)
Proceeds from Issuance of Senior Notes, Net	—	1,086
Repayment of Senior Notes	(384)	(1,096)
Repayment of Capital Lease Obligation	(49)	(44)
Distributions to Noncontrolling Interest Owners and Other	(37)	(47)
Net Cash Used in Financing Activities	(266)	(224)
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	8	(646)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	713	1,210

Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 721	$ 564

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

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

	Attributable to Noble Energy						
	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Non-controlling Interests	Total Equity
December 31, 2017	$ 5	$ 8,438	$ (30)	$ (725)	$ 2,248	$ 683	$ 10,619
Net Income	—	—	—	—	758	58	816
Stock-based Compensation	—	63	—	—	—	—	63
Dividends (32 cents per share)	—	—	—	—	(156)	—	(156)
Purchase and Retirement of Common Stock	—	(233)	—	—	—	—	(233)
Clayton Williams Energy Acquisition	—	(25)	—	—	—	—	(25)
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(35)	(35)
Contributions from Noncontrolling Interest Owners	—	—	—	—	—	348	348
Other	—	6	3	(6)	—	(6)	(3)
September 30, 2018	$ 5	$ 8,249	$ (27)	$ (731)	$ 2,850	$ 1,048	$ 11,394
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

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 (until April 2018); Eastern Mediterranean; and West Africa. Our Midstream segment develops, owns, operates 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, 2018 and December 31, 2017 and for the three and nine months ended September 30, 2018 and 2017 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and equity for such periods. Certain prior-period amounts have been reclassified to conform to the current period presentation. For the periods presented, net income is materially consistent with comprehensive income or loss.

Operating results for the three and nine months ended September 30, 2018 are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

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, 2017.

Consolidation Our consolidated financial statements include our accounts, the accounts of subsidiaries which Noble Energy wholly owns, and the accounts of Noble Midstream Partners LP (Noble Midstream Partners), which is considered a variable interest entity (VIE) for which Noble Energy is the primary beneficiary. In addition, we use the equity method of accounting for investments in entities that we do not control, but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

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.

Investment in Shares of Tamar Petroleum Ltd. We account for our investment in shares of Tamar Petroleum Ltd. at fair value and record changes in fair value in other non-operating (income) expense, net in our consolidated statements of operations. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.

Goodwill As of September 30, 2018, our consolidated balance sheet includes goodwill of $1.4 billion, which is allocated to our Texas and Midstream reporting units. Goodwill is not amortized to earnings but is assessed for impairment on an annual basis during third quarter, or more frequently as circumstances require, at the reporting unit level.

We conducted a qualitative goodwill impairment assessment as of September 30, 2018 by examining relevant events and circumstances which could have an impact on our goodwill. Having assessed the totality of such events and circumstances, 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 values of the reporting units are less than their carrying values. However, regardless of the outcome of the qualitative review, we decided to conduct 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 values of the Texas and Midstream reporting units exceeded their carrying values, including goodwill, and therefore, we concluded no impairment existed as of September 30, 2018.

Intangible Assets Intangible assets consist of customer contracts and relationships acquired by Noble Midstream Partners in its acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte). We recorded the intangible assets at their estimated fair values at the date of acquisition. Amortization is calculated using the straight-line method, which reflects the pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible assets, which is currently over periods of seven to 13 years. As of September 30, 2018, the net book value of the intangible assets was $318 million. Amortization expense of $8 million and $22 million for the three and nine months ended

September 30, 2018, respectively, is included in depreciation, depletion and amortization expense in our consolidated statements of operations. Intangible assets with finite useful lives are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. See Note 3. Acquisitions and Divestitures.

Stock Repurchase Program On February 15, 2018, we announced that the Company's Board of Directors authorized a $750 million share repurchase program which expires December 31, 2020. All purchases will be made from time to time in the open market or private transactions, depending on market conditions, and may be discontinued at any time. During third quarter and first nine months of 2018, 3.4 million shares and 7.4 million shares, respectively, of common stock were repurchased and retired at an average purchase price of $30.07 per share and $31.34 per share, respectively.

ASC 606, Revenue from Contracts with Customers Our revenue is derived from the sale of crude oil, NGL and natural gas production, primarily to crude oil refining companies, midstream marketing companies, marketers, industrial companies, electric utility companies, independent power producers and cogeneration facilities, among others. We account for revenue in accordance with ASC 606, *Revenue from Contracts with Customers* (ASC 606), which we adopted on January 1, 2018 using the modified retrospective method. Under ASC 606, performance obligations are the unit of account and generally represent distinct goods or services that are promised to customers. For sales of crude oil, NGLs and natural gas, each unit sold is generally considered a distinct good and the related performance obligation is generally satisfied at a point in time. We recognize our sales revenues at a point in time and upon delivery to a customer at the contractually stated price and for the quantity of product delivered. In Israel, because our contracts are long-term arrangements, we recognize revenues from the sale of natural gas over the life of the contract based on the quantity of natural gas delivered.

ASC 606 provides additional clarification related to principal versus agent considerations. Under this guidance, we record revenue on a gross basis if we control a promised good or service before transferring it to a customer. For example, gathering, processing, transportation and fractionation costs incurred before transfer of control to the customer at the tailgate of a plant are accounted for as fulfillment costs and are presented as a component of gathering, transportation and processing expense in our consolidated statements of operations. On the other hand, we record revenue on a net basis if our role is to arrange for another entity to provide the goods or services. For example, costs incurred after control over the product has transferred to the customer, such as at the wellhead or inlet of a plant, are recorded as a reduction of the transaction price received within revenue.

Certain of our contracts for the sale of commodities contain embedded derivatives. We have elected the normal purchases and normal sales scope exception as provided by ASC 815, *Derivatives and Hedging*, and will account for such contracts in accordance with ASC 606.

In the US, we enter into marketing agreements with our non-operating partners to market and sell their share of production to third parties. We have determined that we act as an agent in such arrangements and account for such arrangements on a net basis.

ASC 606 adoption did not have an impact on the opening balance of retained earnings. The adoption resulted in a de minimis decrease of $2 million to revenues and expenses for third quarter 2018 and an increase of $5 million to revenues and expenses for the first nine months of 2018, respectively, but did not affect operating or net income or operating cash flows. The comparative information for the prior period has not been recast and continues to be reported under the accounting standards in effect for the period. Adoption of the new standard did not impact our financial position, and we do not expect that it will do so going forward. See Note 11. Segment Information for disaggregation of revenue by commodity and geographic location.

Changes to the presentation of commodity sales revenue and production expense resulted from our assessment of certain contractual arrangements under principal versus agent guidance and assessment of control under ASC 606. In particular, we have determined that the processor is our customer with regard to the sale of natural gas at the wellhead or the sale of NGLs at the tailgate. This is a change from previous conclusions reached under principal versus agent guidance per ASC 605, *Revenue Recognition*, where we previously retained control over our production until the sale to the end customer in the downstream markets. As such, effective January 1, 2018, revenues and expenses are presented on a net basis within revenues in our consolidated statements of operations at the time control over production is transferred to the processor under these arrangements.

Following the control model in ASC 606, we determined that we remain the principal in arrangements with end customers, such as when we take product in-kind at the tailgate and when we are directly responsible for the transportation and marketing of our production in the downstream markets. In such arrangements, we record NGL and natural gas sales and production expense on a gross basis.

Our commodity sales contracts in the US are index-based and, thus, include variable consideration. In accordance with ASC 606, we allocate variable consideration (market price) to the distinct commodities transferred in the period, but not to the future obligations to deliver production. Such allocation represents the amount of consideration to which we are entitled for deliveries of our commodities to-date and represents the value of product delivered to the customer. Therefore, our revenue is recognized at the time of delivery and is the product of the volume delivered and the index-based price for the period.

The following is a summary of our types of revenue arrangements by commodity and geographic location.

EXPLORATION AND PRODUCTION (E&P) REVENUE ARRANGEMENTS

Crude Oil Sale Arrangements – US We sell the majority of our US crude oil production under short-term contracts at market-based prices, adjusted for location, quality and transportation charges. Market-based pricing is based on the price index applicable for the location of the sale.

We sell our crude oil production either at the lease location or in downstream markets. Crude oil production at the lease location is sold through netback arrangements, under which we sell crude oil net of transportation costs incurred by the purchaser. We record revenue, net, at the lease location when the customer receives delivery of the product.

When we move our crude oil production from the lease location to the downstream markets in the US, we incur gathering and transportation costs, which we consider contract fulfillment activities. Such costs are reported as expense within gathering, transportation and processing expense in the consolidated statements of operations. Revenue from the sale of crude oil in downstream markets is recognized upon delivery, as specified in the contract, when control of the product has transferred to the customer.

In second quarter 2018, we entered into a long-term contract to sell firm quantities of crude oil under index-based prices adjusted by applicable fees, including transportation, insurance, and marketing.

Crude Oil Buy/Sell Transactions – US We enter into buy/sell arrangements that effect a change in location and/or grade with required repurchase of crude oil at a delivery point. The sale and repurchase of crude oil is settled at the same contractually fixed price (before application of transportation and grade deductions) on a net basis. We account for these transactions on a net basis, in accordance with ASC 845, *Nonmonetary Transactions*. We record the residual transportation fee as transportation expense within gathering, transportation and processing expense in the consolidated statements of operations.

Crude Oil Sale Arrangements – West Africa Our share of crude oil and condensate from the Aseng, Alen and Alba fields is sold at market-based prices to Glencore Energy UK Ltd. (Glencore Energy). Crude oil is priced at a Dated Brent FOB net realized price achieved by Glencore Energy and is adjusted by applicable fees, including transportation, insurance, and marketing. We recognize revenue on the sale of crude oil to Glencore Energy at the time crude oil cargo is loaded onto the tanker and control transfers to Glencore Energy. We record revenue at the realized price received from Glencore Energy, net of applicable fees.

Natural Gas and NGLs Sale Arrangements – US Certain of our commodity contracts in the US are for the sale of natural gas to processors at prevailing market prices. We evaluate the contract terms of these arrangements to determine whether the processor is a service provider or a customer on a contract by contract basis. In arrangements where we determine that we sold our product to the processor, we treat the processor as a customer and record revenue when the processor takes physical possession of the natural gas and NGLs and in the amount of proceeds expected to be received, net of any fees or deductions charged by the processor.

In other natural gas processing arrangements, we receive natural gas and NGL products "in-kind" after processing at the tailgate of the plant. In these arrangements, we are responsible for the transportation, fractionation and marketing costs of our production. In such cases, where we have determined that the processor is a service provider, we record the sale of natural gas and NGLs and applicable gathering, processing, transportation and fractionation fees on a gross basis at the time the product is delivered to the end customer.

Natural Gas Purchase and Sale Arrangements – US We enter into purchase transactions and separate sale transactions with third parties at prevailing market prices to mitigate unutilized pipeline transportation commitments, primarily related to retained Marcellus Shale firm transportation agreements. Revenues and expenses from the sales and purchases are recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer.

Natural Gas Sale Arrangements – West Africa We sell our share of natural gas production from the Alba field under a long-term contract for $0.25 per MMBtu to a methanol plant, a liquefied petroleum gas (LPG) plant, a liquefied natural gas (LNG) plant and a power generation plant. We recognize revenue upon transfer of control of product to these processors.

Natural Gas Sale Arrangements – Israel Our natural gas sales in Israel are primarily based on long-term contracts with fixed volume commitments over the life of the arrangements. Our performance obligations for the sale of natural gas are satisfied over time using production output to measure progress. The nature of these contracts gives rise to several types of variable consideration, including index-based annual price escalations, commodity-based index pricing, tiered pricing and sales price discounts in periods of volume deficiencies. Additionally, the majority of our sales contracts contain take-or-pay provisions where the customers are required to purchase a contractual minimum over varying time periods. Where the variable consideration is related to market-based pricing or index-based escalations of a fixed base price, we have elected the variable consideration allocation exception pursuant to ASC 606. We record revenue related to the volumes delivered at the contract price at the time of delivery. To date, there have been no material impacts of variability in consideration due to tiered pricing, take-or-pay provisions and/or volume deficiency discounts. We believe that any variability due to future sales price adjustments associated with potential volume deficiencies will not have a significant impact on our financial position or results of operations.

Transaction Price Allocated to Remaining Performance Obligations – Israel Remaining performance obligations represent the transaction price of firm sales arrangements for which volumes have not been delivered. Pursuant to ASC 606, short and long-term interruptible contracts and long-term dedicated production agreements are excluded from the disclosure due to uncertainty associated with estimating future production volumes and future market prices. However, certain of our natural gas sales contracts in Israel have fixed annual sales volumes and fixed base pricing with annual index escalations. The following table includes estimated revenues based upon those certain agreements with fixed minimum take-or-pay sales volumes. Our actual future sales volumes under these agreements may exceed future minimum volume commitments.

(millions)	Oct - Dec 2018	2019	2020	Total
Natural Gas Revenues [1]	$ 54	$ 137	$ 169	$ 360

(1) The remaining performance obligations are estimated utilizing the contractual base or floor price provision in effect. Our future revenues from the sale of natural gas under these associated contracts will vary from the amounts presented above due to components of variable consideration above the contractual base or floor provision, such as index-based escalations and market price changes.

MIDSTREAM REVENUE ARRANGEMENTS

Midstream Services Arrangements Our Midstream segment revenues are derived from fixed fee contract arrangements for gathering, transportation and storage services. We have determined that our performance obligations for the provision of such services are satisfied over time using volumes delivered as the measure of progress. ASC 606 adoption did not have an impact on the recognition, measurement and presentation of our midstream revenues and expenses.

Crude Oil Purchase and Sale Arrangements – US As part of the Saddle Butte acquisition in first quarter 2018, we acquired a pipeline and associated third party contracts which include transactions for the purchase and sale of crude oil with varying counterparties. Revenues and expenses from the sales and purchases are recorded on a gross basis as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. The purchases and sales of crude oil are recorded at the prevailing market prices.

Recently Issued Accounting Standards

Leases In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-02 (ASU 2016-02): *Leases.* The standard requires lessees to recognize a right of use asset and lease liability on the balance sheet for the rights and obligations created by leases. ASU 2016-02 also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. In July 2018, the FASB issued Accounting Standards Update No. 2018-11 (ASU 2018-11): *Leases (Topic 842): Targeted Improvements*, which provides for an alternative transition method by allowing entities to initially apply the new leases standard at the adoption date (such as January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption (comparative periods presented in the financial statements will continue to be in accordance with current GAAP (Topic 840, 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, field services and well equipment, office space and other assets. We will adopt the new standard on the effective date of January 1, 2019, using a modified retrospective approach as permitted under ASU 2018-11. We plan to make certain elections allowing us to not reassess contracts that commenced prior to adoption of the standard, not recognize right of use assets or lease liabilities associated with leases of terms less than 12 months, and account for existing land easements under our current accounting policy.

We continue to execute a project plan, which includes contract review and assessment, data collection, and evaluation of our systems, processes and internal controls. In addition, we are implementing a new lease accounting software which will facilitate the adoption of this standard. Although we continue to assess the impact of the standard on our consolidated financial statements, we believe adoption and implementation will result in an increase to assets and liabilities, as well as additional disclosures. We do not expect a material impact on our consolidated statement of operations.

Accumulated Other Comprehensive Income In February 2018, the FASB issued Accounting Standards Update No. 2018-02 (ASU 2018-02): *Income Statement – Reporting Comprehensive Income,* to allow reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. ASU 2018-02 will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. As of September 30, 2018, we have a disproportionate tax effect of approximately $7 million stranded in accumulated other comprehensive income. We are currently evaluating the provisions of ASU 2018-02.

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 standard, we will perform our 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.

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 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 standard is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. From evaluation of our current credit portfolio, which includes receivables for commodity sales, joint interest billings due from partners and other receivables, historical credit losses have been de minimis and we believe that our expected future credit losses would not be significant. As such, we do not believe adoption of the standard will have a material impact on our financial statements.

Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities In August 2017, the FASB issued Accounting Standards Update No. 2017-12 (ASU 2017-12): *Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities.* The update is intended to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition to that main objective, ASU 2017-12 makes certain targeted improvements to simplify the application of the hedge accounting guidance in current US GAAP. The amended standard is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We are currently evaluating the provisions of ASU 2017-12.

Intangibles—Goodwill and Other—Internal-Use Software In August 2018, the FASB issued Accounting Standards Update No. 2018-15 (ASU 2018-15): *Intangibles—Goodwill and Other—Internal-Use Software,* to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The amended standard is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the provisions of ASU 2018-15.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2018	2017	2018	2017
Sales of Purchased Oil and Gas and Other				
Sales of Purchased Oil and Gas [(1)]	$ 72	$ —	$ 191	$ —
Income from Equity Method Investees	44	46	140	125
Midstream Services Revenues – Third Party	21	7	49	12
Total	$ 137	$ 53	$ 380	$ 137
Production Expense				
Lease Operating Expense	$ 124	$ 151	$ 411	$ 414
Production and Ad Valorem Taxes	47	31	151	104
Gathering, Transportation and Processing Expense	97	93	292	333
Other Royalty Expense	5	5	32	15
Total	$ 273	$ 280	$ 886	$ 866
Exploration Expense				
Leasehold Impairment	$ —	$ 33	$ —	$ 51
Seismic, Geological and Geophysical	4	7	17	20
Staff Expense	14	11	41	40
Other	7	13	31	25
Total	$ 25	$ 64	$ 89	$ 136
Other Operating Expense (Income), Net				
Marketing Expense [(2)]	$ 11	$ 6	$ 21	$ 39
Purchased Oil and Gas [(1)]	76	—	204	—
Clayton Williams Energy Acquisition Expenses	—	4	—	98
Gain on Asset Retirement Obligation Revisions [(3)]	(10)	(42)	(21)	(42)
Other, Net	1	17	18	37
Total	$ 78	$ (15)	$ 222	$ 132
Other Non-Operating (Income) Expense, Net				
Gain on Investment in Shares of Tamar Petroleum Ltd., Net [(4)]	$ (32)	$ —	$ (6)	$ —
Loss (Gain) on Extinguishment of Debt, Net	—	98	(3)	98
Other, Net	(2)	2	(1)	(4)
Total	$ (34)	$ 100	$ (10)	$ 94

(1) As part of the Saddle Butte acquisition in first quarter 2018, we acquired certain contracts which include the purchase and sale of crude oil with third parties. In addition, we entered into certain transactions beginning in first quarter 2018 for the purchase of third party natural gas and the subsequent sale of natural gas to other third parties. The natural gas is transported through firm transportation capacity we retained following the Marcellus Shale upstream divestiture in second quarter 2017 and is part of our mitigation efforts to utilize capacity and reduce our financial commitment. See Note 11. Segment Information and Note 12. Marcellus Shale Firm Transportation Contracts.

(2) Amounts relate to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments primarily in the DJ Basin for 2018 and in the DJ Basin and Marcellus Shale for 2017 (prior to the Marcellus Shale upstream divestiture in second quarter 2017).

(3) Gain resulted from downward asset retirement obligation revisions in locations where we have no remaining assets. See Note 8. Asset Retirement Obligations.

(4) Amounts for third quarter and first nine months of 2018 include a gain of $15 million and a loss of $25 million, respectively, due to changes in the fair value of our investment in shares of Tamar Petroleum Ltd. In addition, third quarter and first nine months of 2018 include dividend income of $17 million and $31 million, respectively. See Note 6. Fair Value Measurements and Disclosures.

Balance Sheet Information Other balance sheet information is as follows:

(millions)	September 30, 2018	December 31, 2017
Accounts Receivable, Net		
Commodity Sales	$ 475	$ 455
Joint Interest Billings	147	207
Other	90	103
Allowance for Doubtful Accounts	(14)	(17)
Total	$ 698	$ 748
Other Current Assets		
Inventories, Materials and Supplies	$ 52	$ 66
Inventories, Crude Oil	34	16
Assets Held for Sale (1)	—	629
Restricted Cash (2)	1	38
Investment in Shares of Tamar Petroleum Ltd. (3)	165	—
Prepaid Expenses and Other Current Assets	57	31
Total	$ 309	$ 780
Other Noncurrent Assets		
Equity Method Investments (4)	$ 295	$ 305
Customer-Related Intangible Assets (5)	318	—
Mutual Fund Investments	58	57
Net Deferred Income Tax Asset	25	25
Other Assets, Noncurrent	78	74
Total	$ 774	$ 461
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 112	$ 84
Commodity Derivative Liabilities	294	58
Income Taxes Payable	57	18
Asset Retirement Obligations (6)	92	51
Interest Payable	87	67
Current Portion of Capital Lease Obligations	44	61
Liabilities Associated with Assets Held for Sale (1)	—	55
Compensation and Benefits Payable	76	98
Other Liabilities, Current	123	86
Total	$ 885	$ 578
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$ 182	$ 197
Asset Retirement Obligations (6)	582	824
Marcellus Shale Firm Transportation Commitment (7)	69	76
Production and Ad Valorem Taxes	60	69
Commodity Derivative Liabilities	100	15
Other Liabilities, Noncurrent	82	64
Total	$ 1,075	$ 1,245

(1) There are no assets held for sale at September 30, 2018. Assets held for sale at December 31, 2017 include assets in the Greeley Crescent area of the DJ Basin, a 7.5% interest in the Tamar field, offshore Israel, our investment in Southwest Royalties, Inc. acquired in the Clayton Williams Energy Acquisition, and the CONE investments. Liabilities associated with assets held for sale primarily represent asset retirement obligations and other liabilities to be assumed by the purchaser. See Note 3. Acquisitions and Divestitures.

(2) Balance at September 30, 2018 represents Noble Midstream Partners collateral on letters of credit. Balance at December 31, 2017 represents amount held in escrow pending closing of the Saddle Butte acquisition. See Note 3. Acquisitions and Divestitures.
(3) Amount relates to our investment in shares of Tamar Petroleum Ltd. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.
(4) In 2018, we sold our units in CNX Midstream Partners LP, which was previously recorded as an equity method investment. At December 31, 2017, this investment was included in assets held for sale. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.
(5) Amount relates to intangible assets acquired in the Saddle Butte acquisition and is net of $22 million of accumulated amortization. See Note 3. Acquisitions and Divestitures.
(6) The decrease in asset retirement obligations during the nine months ended September 30, 2018 is primarily due to liabilities assumed by purchasers of divested assets during the period, partially offset by revisions, accretion and additional liabilities incurred. See Note 8. Asset Retirement Obligations.
(7) Amounts relate to the long-term portion of retained firm transportation agreements. The current portion of these obligations is included in other liabilities, current. See Note 12. Marcellus Shale Firm Transportation Contracts.

Reconciliation of Total Cash We define total cash as cash, cash equivalents and restricted cash. The following table provides a reconciliation of total cash:

	Nine Months Ended September 30,	
(millions)	2018	2017
Cash and Cash Equivalents at Beginning of Period	$ 675	$ 1,180
Restricted Cash at Beginning of Period	38	30
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	$ 713	$ 1,210
Cash and Cash Equivalents at End of Period	$ 720	$ 564
Restricted Cash at End of Period	1	—
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 721	$ 564

Note 3. Acquisitions and Divestitures

2018 Asset Transactions

Divestiture of Gulf of Mexico Assets On February 15, 2018, we announced that we had signed a definitive agreement to sell our Gulf of Mexico assets, including all of our interests in producing properties and undeveloped acreage, for cash consideration of $480 million, along with the assumption, by the purchaser, of all abandonment obligations associated with the properties. As a result, we recorded impairment expense of $168 million during first quarter 2018.

In second quarter 2018, we closed the transaction with an effective date of January 1, 2018. After consideration of customary closing adjustments, to date we have received net proceeds of $383 million and recorded a loss of $24 million.

In addition, a cumulative contingent payment of up to $100 million is payable to us in the period after the closing of the transaction, beginning third quarter 2018, through the end of 2022, determined quarterly, at a rate of $2 per barrel produced by these assets when the average purchase price for Light Louisiana Sweet (LLS) crude oil exceeds $63 per barrel, and if produced crude oil volumes exceed certain minimum thresholds. As of September 30, 2018, no amounts have been accrued related to the contingent payment.

Proved reserves associated with these properties totaled approximately 23 MMBoe as of December 31, 2017.

Divestiture of 7.5% Interest in Tamar Field On March 14, 2018, we closed the sale of a 7.5% working interest in the Tamar field to Tamar Petroleum Ltd. (Tamar Petroleum), a publicly traded entity on the Tel Aviv Stock Exchange (TASE: TMRP). Total consideration included cash and 38.5 million shares of Tamar Petroleum that had a publicly traded value of $224 million. The transaction had an effective date of January 1, 2018 and, after consideration of closing adjustments and before consideration of taxes, we received $484 million of cash. Proved reserves related to the 7.5% interest totaled approximately 502 Bcf, or approximately 84 MMBoe, as of December 31, 2017.

The Tamar Petroleum shares are subject to certain temporary lock-up provisions and have no voting rights. Upon subsequent sale of the shares to a third party, the voting rights will be restored and granted to the third party. Due to the lock-up provisions associated with the Tamar Petroleum shares, we initially attributed $190 million of fair value to the shares, or 15% lower than the publicly traded value on the TASE. These shares are being accounted for at fair value, and we recorded changes in fair value of $15 million and $25 million for third quarter and first nine months of 2018, respectively. See Note 2. Basis of Presentation and Note 6. Fair Value Measurements and Disclosures.

Total consideration received from the sale was applied to the field's basis and resulted in the recognition of a pre-tax gain of $376 million. In connection with the transaction, we incurred tax expense of $86 million.

Subsequent to quarter end, on October 2 and October 3, 2018, we sold 21.9 million and 16.6 million shares of Tamar Petroleum, respectively, in over the counter transactions for pre-tax proceeds of $163 million, net of transaction expenses. The sales of the 7.5% working interest in the Tamar field and of the Tamar Petroleum shares are in accordance with the terms of the Israel Natural Gas Framework that requires us to reduce our ownership interest in the Tamar field from 32.5% to 25% by year-end 2021.

Divestiture of Southwest Royalties In January 2018, we closed the sale of our investment in Southwest Royalties, Inc. (Southwest Royalties), a subsidiary of Clayton Williams Energy, Inc. (Clayton Williams Energy), which we acquired in the acquisition of Clayton Williams Energy (Clayton Williams Energy Acquisition) in 2017. We received proceeds of $60 million, resulting in no gain or loss recognition on the sale of these assets.

Divestiture of Marcellus Shale CONE Gathering In January 2018, we closed the sale of our 50% interest in CONE Gathering LLC (CONE Gathering) to CNX Resources Corporation. CONE Gathering owns the general partner of CNX Midstream Partners LP (CNX Midstream Partners, NYSE: CNXM). We received proceeds of $308 million in cash and recognized a pre-tax gain of $196 million.

After the sale, we held 21.7 million common units, representing a 34.1% limited partner interest, in CNX Midstream Partners. During second quarter 2018, we sold 7.5 million of the common units, receiving net proceeds of approximately $135 million, net of placement agent fees, and recognized a gain of $109 million.

During third quarter 2018, we sold the remaining 14.2 million common units, which represented a 22.3% limited partner interest in CNX Midstream Partners. We received net proceeds of approximately $248 million, net of underwriting fees, and recognized a gain of $198 million. The investment was previously accounted for under the equity method of accounting.

Divestiture of Greeley Crescent Assets In September 2018, we closed the sale of assets in the Greeley Crescent area of the DJ Basin. We received proceeds of $64 million, resulting in no gain or loss recognition on the sale of these assets.

Noble Midstream Partners Saddle Butte Acquisition On January 31, 2018, Black Diamond Gathering LLC (Black Diamond), an entity formed by Black Diamond Gathering Holdings LLC, a wholly-owned subsidiary of Noble Midstream Partners, and Greenfield Midstream, LLC (Greenfield), completed the acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte) from Saddle Butte Pipeline II, LLC. Saddle Butte owned a large-scale integrated gathering system, located in the DJ Basin, which we subsequently renamed the Black Diamond gathering system.

Consideration totaled $681 million, which included $663 million of cash and assumption of $18 million of liabilities. Greenfield funded approximately $343 million of the purchase price, which is reflected as a contribution from noncontrolling interest within our consolidated statement of equity, and Noble Midstream Partners funded the remainder. We consolidate Black Diamond as a VIE and reflect the third-party ownership within noncontrolling interest within our consolidated statement of equity.

We accounted for the transaction as a business combination using the acquisition method. The total purchase price was allocated to assets acquired and liabilities assumed based on the fair value at the acquisition date. We have recognized goodwill for the amount of the purchase price exceeding the fair value of the assets acquired. Allocated fair value included: $206 million to property, plant and equipment; $340 million to customer-related intangible assets (acquired customer contracts); and $110 million to implied goodwill. The purchase price allocation is preliminary as certain data necessary to complete the purchase price allocation is not yet available, such as analysis of the 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.

Other Divestitures During the first nine months of 2018, we also closed the sale of certain other smaller US onshore proved and unproved properties and received total cash consideration of $58 million, recording a gain of $4 million.

2017 Asset Transactions

Delaware Basin Acquisition During the first nine months of 2017, we closed a bolt-on acquisition in the Delaware Basin for $301 million, approximately $246 million of which was allocated to undeveloped leasehold costs. The acquisition included interests in seven producing wells, four of which are operated by us.

Clayton Williams Energy Acquisition On April 24, 2017, we completed the Clayton Williams Energy Acquisition. The acquisition was effected through the issuance of 56 million shares of Noble Energy common stock, with a fair value of $1.9 billion, and cash consideration of $637 million, for total consideration of $2.5 billion, in exchange for all of the outstanding Clayton Williams Energy shares, including stock options, restricted stock awards and warrants.

The transaction was accounted for as a business combination using the acquisition method. The following table represents the final allocation of the total purchase price of Clayton Williams Energy to the assets acquired and liabilities assumed, based on the fair value 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.

(millions)		
Fair Value of Common Stock Issued	$	1,851
Plus: Cash Consideration Paid to Clayton Williams Energy Stockholders		637
Total Purchase Price	$	2,488
Plus Liabilities Assumed by Noble Energy:		
Accounts Payable		99
Other Current Liabilities		38
Long-Term Deferred Tax Liability		515
Long-Term Debt		595
Asset Retirement Obligations		63
Total Purchase Price Plus Liabilities Assumed	$	3,798

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

(millions)		
Cash and Cash Equivalents	$	21
Other Current Assets		70
Oil and Gas Properties:		
Proved Reserves		722
Undeveloped Leasehold Costs		1,571
Gathering and Processing Assets		48
Asset Retirement Costs		63
Other Noncurrent Assets		12
Implied Goodwill		1,291
Total Asset Value	$	3,798

In connection with the acquisition, we assumed, and then subsequently retired in second quarter 2017, all of Clayton Williams Energy's long-term debt at a cost of $595 million. The fair value measurements of long-term debt were estimated based on the early redemption prices and represented Level 1 inputs.

The fair value measurements of crude oil and natural gas properties and asset retirement obligations were based on inputs that are not observable in the market and, therefore, represented 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 were the most sensitive.

Based upon the final purchase price allocation, we recognized $1.3 billion of goodwill, all of which was assigned to the Texas reporting unit.

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, 2017. 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.

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, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except per share amounts)	2018 [1]	2017	2018 [1]	2017
Revenues	$ 1,273	$ 960	$ 3,789	$ 3,102
Net Income (Loss) and Comprehensive Income (Loss) Attributable to Noble Energy	227	(133)	758	(1,561)
Net Income (Loss) Attributable to Noble Energy per Common Share				
Basic	$ 0.47	$ (0.27)	$ 1.57	$ (3.21)
Diluted	$ 0.47	$ (0.27)	$ 1.56	$ (3.21)

(1) No pro forma adjustments were made for the period as Clayton Williams Energy operations are included in our historical results.

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of all of our Marcellus Shale upstream assets, which were primarily natural gas properties. The purchase price totaled $1.2 billion, and we received $1.0 billion of net cash proceeds, after consideration of customary adjustments, at closing. The purchase 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. 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 5. 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. See Note 12. Marcellus Shale Firm Transportation Contracts.

During second quarter 2017, production from the Marcellus Shale upstream assets totaled 393 MMcfe/d. 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.

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 Noble Energy 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 consists of gathering systems across Noble Energy's Wells Ranch and East Pony development areas in the DJ Basin.

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.

Noble Midstream Partners 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 $66.5 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 crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas.

Note 4. 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 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Unsettled Commodity Derivative Instruments As of September 30, 2018, the following crude oil derivative contracts were outstanding:

				Swaps		Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Swaps	NYMEX WTI	66,000	$ —	$ 60.30	$ —	$ —	$ —
2018	Collars	NYMEX WTI	18,000	—	—	—	50.42	58.82
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	Swaps	ICE Brent	2,000	—	59.00	—	—	—
2018	Collars	ICE Brent	2,000	—	—	—	50.00	55.25
2018	Three-Way Collars	ICE Brent	5,000	—	—	43.00	50.00	59.50
2018	Basis Swaps	(1)	20,000	(2.30)	—	—	—	—
2019	Swaps	NYMEX WTI	44,000	—	58.37	—	—	—
2019	Three-Way Collars	NYMEX WTI	11,000	—	—	52.05	62.05	75.84
2019	Swaps	ICE Brent	5,000	—	57.00	—	—	—
2019	Three-Way Collars	ICE Brent	3,000	—	—	43.00	50.00	64.07
2019	Basis Swaps	(1)	27,000	(3.23)	—	—	—	—
2020	Swaption (2)	NYMEX WTI	5,000	—	61.79	—	—	—
2020	Basis Swaps	(1)	15,000	(5.01)	—	—	—	—

(1) We have entered into crude oil basis swap contracts in order to establish a fixed amount for 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.

(2) 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.

As of September 30, 2018, the following natural gas derivative contracts were outstanding:

				Swaps		Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Three-Way Collars	NYMEX HH	120,000	$ —	$ —	$ 2.50	$ 2.88	$ 3.65
2019	Three-Way Collars	NYMEX HH	104,000	—	—	2.25	2.65	2.95
2019	Basis Swaps	(1)	52,000	(0.74)	—	—	—	—

(1) We have entered into natural gas basis swap contracts in order to establish a fixed amount for the differential between index pricing for Colorado Interstate Gas and NYMEX Henry Hub. The weighted average differential represents the amount of reduction to NYMEX Henry Hub prices for the notional volumes covered by the basis swap contracts.

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

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	September 30, 2018		December 31, 2017		September 30, 2018		December 31, 2017	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments	Current Assets	$ —	Current Assets	$ 2	Current Liabilities	$ 294	Current Liabilities	$ 58
	Noncurrent Assets	—	Noncurrent Assets	—	Noncurrent Liabilities	100	Noncurrent Liabilities	15
Total		$ —		$ 2		$ 394		$ 73

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2018	2017	2018	2017
Cash Paid (Received) in Settlement of Commodity Derivative Instruments				
Crude Oil	$ 68	$ (4)	$ 164	$ (20)
Natural Gas	(1)	—	(4)	2
Total Cash Paid (Received) in Settlement of Commodity Derivative Instruments	67	(4)	160	(18)
Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	85	27	316	(64)
Natural Gas	3	(1)	7	(63)
Total Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments	88	26	323	(127)
Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	153	23	480	(84)
Natural Gas	2	(1)	3	(61)
Total Loss (Gain) on Commodity Derivative Instruments	$ 155	$ 22	$ 483	$ (145)

Note 5. Debt

Debt consists of the following:

	September 30, 2018		December 31, 2017	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Revolving Credit Facility, due March 9, 2023	$ —	—%	$ 230	2.27%
Noble Midstream Services Revolving Credit Facility, due March 9, 2023	50	3.32%	85	2.75%
Noble Midstream Services Term Loan Credit Facility, due July 31, 2021	500	3.17%	—	—%
Leviathan Term Loan Facility, due February 23, 2025	—	—%	—	—%
Senior Notes, due May 1, 2021 (1)	—	—%	379	5.63%
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	600	3.85%	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	500	4.95%	500	4.95%
Other Senior Notes and Debentures (2)	92	7.13%	92	7.13%
Capital Lease Obligations	234	—%	273	—%
Total	6,676		6,859	
Unamortized Discount	(23)		(24)	
Unamortized Premium (1)	—		12	
Unamortized Debt Issuance Costs	(38)		(40)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	6,615		6,807	
Less Amounts Due Within One Year:				
Capital Lease Obligations	(44)		(61)	
Long-Term Debt Due After One Year	$ 6,571		$ 6,746	

(1) In second quarter 2018, we redeemed all of the Senior Notes due May 1, 2021, and expensed the associated premium. See *Redemption of Senior Notes*, below.

(2) Includes $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 7.13%.

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

In first quarter 2018, we extended the maturity date of the Revolving Credit Facility from August 2020 to March 2023. As of September 30, 2018, no borrowings were outstanding under the Revolving Credit Facility.

Noble Midstream Services Revolving Credit Facility Noble Midstream Services, LLC (Noble Midstream Services), a subsidiary of Noble Midstream Partners, maintains a 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.

In first quarter 2018, the capacity was increased from $350 million to $800 million and the maturity date was extended from September 2021 to March 2023.

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.

During third quarter 2018, $480 million was paid on the Noble Midstream Services Revolving Credit Facility through the issuance of a new term loan credit facility. See *Noble Midstream Services Term Loan Credit Facility* below. As of September 30, 2018, $50 million was outstanding under the Noble Midstream Services Revolving Credit Facility.

Noble Midstream Services Term Loan Credit Facility On July 31, 2018, Noble Midstream Services entered into a Term Credit Agreement (Noble Midstream Services Term Credit Agreement), which provides for a three year senior unsecured term loan credit facility (Noble Midstream Services Term Loan Credit Facility) and permits aggregate borrowings of up to $500 million. Proceeds from the Noble Midstream Services Term Loan Credit Facility were used to repay a portion of the outstanding borrowings under the Noble Midstream Services Revolving Credit Facility and to pay fees and expenses in connection with the Noble Midstream Services Term Loan Credit Facility.

Borrowings under the Noble Midstream Services Term Loan Credit Facility bear interest at a rate equal to, at Noble Midstream Partners' option, either (1) a base rate plus an applicable margin between 0.00% and 0.50% per annum or (2) a Eurodollar rate plus an applicable margin between 1.00% and 1.50% per annum. As of September 30, 2018, $500 million was outstanding under the Noble Midstream Services Term Loan Credit Facility.

The Noble Midstream Services Term Loan Credit Facility contains customary representations and warranties, affirmative and negative covenants, and events of default that are substantially the same as those contained in the Noble Midstream Services Revolving Credit Facility. Upon the occurrence and during the continuation of an event of default under the Noble Midstream Services Term Loan Credit Facility, the lenders may declare all amounts outstanding under the Noble Midstream Services Term Loan Credit Facility to be immediately due and payable and exercise other remedies as provided by applicable law.

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, $625 million of which 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 the 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. As of September 30, 2018, there were no borrowings under the Leviathan Term Loan Facility.

See Note 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Redemption of Senior Notes In May 2018, we redeemed $379 million of Senior Notes due May 1, 2021 that we assumed in the merger (Rosetta Merger) with Rosetta Resources, Inc. in 2015 for $395 million, including $11 million of accrued interest and $5 million of call premium. We fully amortized $10 million of remaining premium and recognized a gain of $5 million, which is reflected in other non-operating (income) expense in our consolidated statements of operations.

Annual Debt Maturities Our nearest annual maturity of outstanding debt, excluding capital lease payments and outstanding balances under the revolving credit facilities and the Noble Midstream Services Term Loan Credit Facility, is $1.0 billion of senior notes which mature in December 2021. The Noble Midstream Services Term Loan Credit Facility matures in July 2021 and the Revolving Credit Facility and Noble Midstream Services Revolving Credit Facility both mature in March 2023. As of September 30, 2018, no other balances are due within the next five years.

Note 6. 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 4. Derivative Instruments and Hedging Activities.

Investment in Tamar Petroleum Ltd. Our investment in shares of Tamar Petroleum was acquired on March 14, 2018. As of March 31, 2018 and June 30, 2018, the fair value of these shares was determined based on the trading price of Tamar Petroleum shares on the TASE, reduced by a discount rate of 15%. The discount rate was based on analysis of historical discounts realized in private placements of public common stock, which we believe represented a reasonable estimate of the impact of the temporary lock-up provisions applicable to the shares we owned.

We sold our shares of Tamar Petroleum in two separate transactions on October 2 and October 3, 2018. As of September 30, 2018, we continued to account for these shares at fair value and reclassified our investment from other noncurrent assets to other current assets on our consolidated balance sheets. The fair value of the shares at September 30, 2018 was determined based on the negotiated selling price, which represented a discount from trading price on the TASE due to the temporary lock up provisions, which transferred to the buyer. See Note 2. Basis of Presentation and Note 3. Acquisitions and Divestitures.

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.

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) [(1)]	Significant Other Observable Inputs (Level 2) [(2)]	Significant Unobservable Inputs (Level 3) [(3)]	Adjustment [(4)]	Fair Value Measurement
September 30, 2018					
Financial Assets:					
Mutual Fund Investments	$ 58	$ —	$ —	$ —	$ 58
Commodity Derivative Instruments	—	35	—	(35)	—
Investment in Tamar Petroleum Ltd. (38,495,575 Shares)	—	165	—	—	165
Financial Liabilities:					
Commodity Derivative Instruments	—	(429)	—	35	(394)
Portion of Deferred Compensation Liability Measured at Fair Value	(73)	—	—	—	(73)
Stock Based Compensation Liability Measured at Fair Value	(14)	—	—	—	(14)
December 31, 2017					
Financial Assets:					
Mutual Fund Investments	$ 57	$ —	$ —	$ —	$ 57
Commodity Derivative Instruments	—	7	—	(5)	2
Financial Liabilities:					
Commodity Derivative Instruments	—	(78)	—	5	(73)
Portion of Deferred Compensation Liability Measured at Fair Value	(71)	—	—	—	(71)
Stock Based Compensation Liability Measured at Fair Value	(10)	—	—	—	(10)

(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 oil and gas properties, goodwill and other intangible assets, are not required to be measured at fair value on a recurring basis. However, these assets are assessed for impairment, and a resulting asset impairment would require the asset be recorded at fair value.

Asset Impairments During first quarter 2018, upon classification of the Gulf of Mexico properties as assets held for sale, we recognized an impairment of $168 million. See Note 3. Acquisitions and Divestitures. For second and third quarter 2018 and the first nine months of 2017, we had no adjustments in fair value related to oil and gas properties.

Additional Fair Value Disclosures

Investment in CNX Midstream Partners Our investment in CNX Midstream Partners, which is included in our Midstream reportable segment, was previously accounted for using the equity method. The fair value of the investment at December 31, 2017, was based on the published market price of the common units at that date. During second quarter 2018, we sold 7.5 million of our 21.7 million common units in CNX Midstream Partners. In third quarter 2018, we sold the remaining 14.2 million common units. See Note 3. Acquisitions and Divestitures.

	September 30, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investment in CNX Midstream Partners (0 Common Units and 21,692,198 Common Units, respectively)	$ —	$ —	$ 70	$ 364

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 Revolving Credit Facility, the Noble Midstream Services Revolving Credit Facility, the Noble Midstream Services Term Loan Credit Facility and the Leviathan Term Loan 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 5. Debt.

Fair value information regarding our debt is as follows:

	September 30, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value [1]	Carrying Amount	Fair Value
Long-Term Debt [2]	$ 6,442	$ 6,498	$ 6,586	$ 7,142

(1) As of September 30, 2018, the fair value of long-term debt approximates the carrying amount, primarily due to the current rising interest rate environment.
(2) Excludes unamortized discount, premium, debt issuance costs and capital lease obligations.

Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs

Capitalized Exploratory Well Costs We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. On a quarterly basis, we review the status of suspended exploratory well costs and assess the development of these projects. If a well is deemed to be noncommercial, the well costs are charged to exploration expense as dry hole cost.

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

(millions)	Nine Months Ended September 30, 2018
Capitalized Exploratory Well Costs, Beginning of Period	$ 520
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	7
Divestitures [1]	(168)
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(1)
Capitalized Exploratory Well Costs Charged to Expense	—
Capitalized Exploratory Well Costs, End of Period	$ 358

(1) Represents costs primarily related to Gulf of Mexico assets.

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

(millions)	September 30, 2018	December 31, 2017
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 8	$ 10
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	350	510
Balance at End of Period	$ 358	$ 520
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	7	8

Undeveloped Leasehold Costs We reclassify undeveloped leasehold costs to proved property costs when, as a result of exploration and development activities, probable and possible resources are reclassified to proved reserves, including proved undeveloped reserves. 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 record impairment expense related to the respective leases or licenses.

As of September 30, 2018, we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of $2.6 billion, including $2.4 billion and $129 million attributable to the Delaware Basin and Eagle Ford Shale, respectively. 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, 2018 primarily included $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 2018, we transferred $259 million and $20 million of undeveloped leasehold costs associated with Delaware Basin and Eagle Ford Shale assets, respectively, to proved properties. These transfers resulted from additions of proved reserves through development activities. In addition, $43 million of capitalized costs associated with Gulf of Mexico leases and licenses and $36 million of capitalized costs associated with other US onshore properties were removed from undeveloped leasehold costs due to divestiture of the associated assets in second quarter and third quarter 2018, respectively. See Note 3. Acquisitions and Divestitures.

Note 8. Asset Retirement Obligations

Asset retirement obligations (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in ARO are as follows:

	Nine Months Ended September 30,	
(millions)	2018	2017
Asset Retirement Obligations, Beginning Balance	$ 875	$ 935
Liabilities Incurred	16	83
Liabilities Settled	(309)	(53)
Revisions of Estimates	67	(56)
Accretion Expense [1]	25	35
Asset Retirement Obligations, Ending Balance	$ 674	$ 944

(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, 2018 Liabilities settled included $216 million and $24 million of liabilities assumed by the purchasers of the Gulf of Mexico properties and Greeley Crescent assets, respectively, and $69 million related to abandonment of US onshore properties, primarily in the DJ Basin, where we have engaged in a program to plug and abandon older vertical wells. Costs associated with these abandonment activities will be incurred over several years. Revisions of estimates were primarily related to increases in cost and timing estimates of $84 million for US onshore, primarily in the DJ Basin, partially offset by decreases in cost and timing estimates of $11 million associated with the North Sea abandonment project and $6 million for wells offshore Israel.

For the Nine Months Ended September 30, 2017 Liabilities incurred included $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 included $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 related 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.

Note 9. Income Taxes

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except percentages)	2018	2017	2018	2017
Current	$ 45	$ 22	$ 194	$ 71
Deferred	14	(115)	(150)	(988)
Total Income Tax Expense (Benefit)	$ 59	$ (93)	$ 44	$ (917)
Effective Tax Rate	19.2%	44.7%	5.1%	36.9%

Changes in US Tax Law On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), which made significant changes to US federal income tax law, including a reduction in the federal corporate tax rate to 21%, effective January 1, 2018. In accordance with US GAAP, we recognized the effect of the rate change on deferred tax assets and liabilities as of December 31, 2017.

On April 2, 2018, the US Department of the Treasury and the Internal Revenue Service released Notice 2018-26, signaling intent to issue regulations related to the transition tax (toll tax) on a one-time “deemed repatriation” of accumulated foreign earnings for the year ended December 31, 2017. Notice 2018-26 clarifies that an Internal Revenue Code Section 965(n) election is available with respect to both current year operating losses and net operating losses from a prior year. As a result, during first quarter 2018, we released the valuation allowance recorded against foreign tax credits that will be utilized against the $268 million toll tax liability we had recorded as of December 31, 2017, resulting in a $252 million tax benefit, and reduced our estimated toll tax liability to $16 million to be paid in installments over eight years. We also recorded a corresponding expense of $107 million for the tax rate change adjustment on the previously utilized net operating losses. The impact on first quarter 2018 total tax expense, related to this additional guidance, was a net $145 million discrete tax benefit.

The ultimate impact of the Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us, as well as additional regulatory guidance that may be issued. In particular, our estimate of the impact of the toll tax is a provisional amount and our current assessment of the global intangible low-taxed income (GILTI) tax is ongoing and subject to legal interpretation. There may be further adjustments to income tax expense or benefit during fourth quarter 2018, when the final amounts are determined in accordance with Staff Accounting Bulletin No. 118.

Effective Tax Rate (ETR) At the end of each interim period, we apply a forecasted annualized effective tax rate (ETR) to current period earnings or loss before tax, which can produce interim ETR fluctuations. The ETR for the three months ended September 30, 2018 varied as compared with the three months ended September 30, 2017 primarily due to a prior year deferred tax benefit resulting from a higher forecasted annualized ETR applied to significant domestic losses.

The ETR for the nine months ended September 30, 2018 varied as compared with the nine months ended September 30, 2017, primarily due to a deferred tax benefit of $145 million recorded discretely in the current year, as discussed above, and a significant deferred tax benefit recorded at the higher prior year US tax rate of 35% on the Marcellus Shale upstream divestiture in second quarter 2017. In addition, the increase in the current income tax expense for the nine months ended September 30, 2018 is primarily due to foreign taxes on a gain associated with the first quarter 2018 divestiture of a 7.5% interest in the Tamar field, offshore Israel.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2014, Israel – 2015 (2013 with respect to Israel Oil Profits Tax) and Equatorial Guinea – 2013.

Note 10. Income Per Share Attributable to Noble Energy

Noble Energy's basic income (loss) per share of common stock is computed by dividing net income (loss) attributable to Noble Energy by the weighted average number of shares of Noble Energy common stock outstanding during each period. The following table summarizes the calculation of basic and diluted income (loss) per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except per share amounts)	2018	2017	2018	2017
Net Income (Loss) and Comprehensive Income (Loss) Attributable to Noble Energy	$ 227	$ (136)	$ 758	$ (1,612)
Weighted Average Number of Shares Outstanding, Basic	482	487	484	464
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	2	—	2	—
Weighted Average Number of Shares Outstanding, Diluted	484	487	486	464
Income (Loss) Per Share, Basic	$ 0.47	$ (0.28)	$ 1.57	$ (3.47)
Income (Loss) Per Share, Diluted	0.47	(0.28)	1.56	(3.47)
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	13	16	14	16

Note 11. Segment Information

We have the following reportable segments: United States (US onshore and Gulf of Mexico (until April 2018)); Eastern Mediterranean (Israel and Cyprus); West Africa (Equatorial Guinea, Cameroon and Gabon); Other International (Suriname, Canada and New Ventures); and Midstream. The Midstream segment includes the consolidated accounts of Noble Midstream Partners, US onshore equity method investments and other US onshore midstream assets.

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

		Oil and Gas Exploration and Production				Midstream		
(millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other[1]	Corporate
Three Months Ended September 30, 2018								
Crude Oil Sales	$ 744	$ 655	$ 2	$ 87	$ —	$ —	$ —	$ —
NGL Sales	166	166	—	—	—	—	—	—
Natural Gas Sales	226	98	122	6	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	1,136	919	124	93	—	—	—	—
Sales of Purchased Oil and Gas	72	26	—	—	—	46	—	—
Income from Equity Method Investees and Other	65	—	—	34	—	31	—	—
Intersegment Revenues	—	—	—	—	—	91	(91)	—
Total Revenues	1,273	945	124	127	—	168	(91)	—
Lease Operating Expense	124	114	7	15	—	—	(12)	—
Production and Ad Valorem Taxes	47	46	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	97	129	—	—	—	28	(60)	—
Other Royalty Expense	5	5	—	—	—	—	—	—
Total Production Expense	273	294	7	15	—	29	(72)	—

		Oil and Gas Exploration and Production				Midstream		
(millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other[1]	Corporate
DD&A	485	414	16	25	1	24	(5)	10
(Gain) Loss on Divestitures, Net	(193)	5	—	—	—	(198)	—	—
Purchased Oil and Gas	76	32	—	—	—	44	—	—
Gain on Asset Retirement Obligation Revisions	(10)	—	—	—	(10)	—	—	—
Loss on Commodity Derivative Instruments	155	140	—	15	—	—	—	—
Gain on Investment in Shares of Tamar Petroleum Ltd., Net	(32)	—	(32)	—	—	—	—	—
Income (Loss) Before Income Taxes	307	31	143	68	(17)	268	(16)	(170)
Three Months Ended September 30, 2017								
Crude Oil Sales	$ 553	$ 487	$ 2	$ 64	$ —	$ —	$ —	$ —
NGL Sales	116	116	—	—	—	—	—	—
Natural Gas Sales	238	93	139	6	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	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)	—
Lease Operating Expense	151	118	9	25	—	—	(1)	—
Production and Ad Valorem Taxes	31	30	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	93	129	—	—	—	20	(56)	—
Other Royalty Expense	5	5	—	—	—	—	—	—
Total Production Expense	280	282	9	25	—	21	(57)	—
DD&A	523	442	18	41	1	10	(1)	12
Gain on Asset Retirement Obligation Revisions	(42)	—	—	—	(42)	—	—	—
Loss on Debt Extinguishment	98	—	—	—	—	—	—	98
Loss on Commodity Derivative Instruments	22	16	—	6	—	—	—	—
(Loss) Income Before Income Taxes	(208)	(115)	109	24	23	58	(12)	(295)
Nine Months Ended September 30, 2018								
Crude Oil Sales	$ 2,266	$ 1,972	$ 6	$ 288	$ —	$ —	$ —	$ —
NGL Sales	449	449	—	—	—	—	—	—
Natural Gas Sales	694	316	362	16	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	3,409	2,737	368	304	—	—	—	—
Sales of Purchased Oil and Gas	191	81	—	—	—	110	—	—
Income from Equity Method Investees and Other	189	—	—	105	—	84	—	—
Intersegment Revenues	—	—	—	—	—	257	(257)	—
Total Revenues	3,789	2,818	368	409	—	451	(257)	—

(millions)	Consolidated	Oil and Gas Exploration and Production: United States	Eastern Mediter-ranean	West Africa	Other Int'l	Midstream: United States	Intersegment Eliminations and Other[1]	Corporate
Lease Operating Expense	411	354	19	56	—	—	(18)	—
Production and Ad Valorem Taxes	151	147	—	—	—	4	—	—
Gathering, Transportation and Processing Expense	292	389	—	—	—	71	(168)	—
Other Royalty Expense	32	32	—	—	—	—	—	—
Total Production Expense	886	922	19	56	—	75	(186)	—
DD&A	1,418	1,214	44	77	1	62	(13)	33
(Gain) Loss on Divestitures, Net	(859)	20	(376)	—	—	(503)	—	—
Asset Impairments	168	168	—	—	—	—	—	—
Purchased Oil and Gas	204	98	—	—	—	106	—	—
Gain on Asset Retirement Obligation Revisions	(21)	—	—	—	(21)	—	—	—
Loss on Commodity Derivative Instruments	483	400	—	83	—	—	—	—
Gain on Investment in Shares of Tamar Petroleum Ltd., Net	(6)	—	(6)	—	—	—	—	—
Income (Loss) Before Income Taxes	860	(94)	678	180	(44)	690	(52)	(498)
Nine Months Ended September 30, 2017								
Crude Oil Sales	$ 1,637	$ 1,383	$ 5	$ 249	$ —	$ —	$ —	$ —
NGL Sales	329	329	—	—	—	—	—	—
Natural Gas Sales	952	534	401	17	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	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	104	102	—	—	—	2	—	—
Gathering, Transportation and Processing Expense	333	416	—	—	—	53	(136)	—
Other Royalty Expense	15	15	—	—	—	—	—	—
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 Exit Activities	2,326	2,326	—	—	—	—	—	—
Clayton Williams Energy Acquisition Expenses	98	98	—	—	—	—	—	—
Loss on Debt Extinguishment	98	—	—	—	—	—	—	98
Gain on Asset Retirement Obligation Revisions	(42)	—	—	—	(42)	—	—	—
Gain on Commodity Derivative Instruments	(145)	(138)	—	(7)	—	—	—	—
(Loss) Income Before Income Taxes	(2,483)	(2,433)	316	162	11	165	(47)	(657)

		Oil and Gas Exploration and Production				Midstream		
(millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other[1]	Corporate
September 30, 2018								
Goodwill [2]	$ 1,401	$ 1,291	$ —	$ —	$ —	$ 110	$ —	$ —
Total Assets [3]	22,147	15,440	3,184	1,208	66	2,318	(150)	81
December 31, 2017								
Goodwill [2]	1,310	1,310	—	—	—	—	—	—
Total Assets	21,476	15,767	2,846	1,308	114	1,357	(163)	247

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

(2) Goodwill in the United States reportable segment is associated with our Texas reporting unit. Goodwill in the Midstream segment is associated with the first quarter 2018 Saddle Butte acquisition.

(3) $318 million of total assets in the Midstream segment relates to intangible assets acquired in the first quarter 2018 Saddle Butte acquisition.

Note 12. Marcellus Shale Firm Transportation Contracts

On June 28, 2017, we closed the sale of all of our Marcellus Shale upstream assets, which were primarily natural gas properties. In connection with the divestiture, we retained certain firm transportation commitments to flow Marcellus Shale natural gas production to various markets inside and outside of the Marcellus Basin. As of September 30, 2018, our financial commitment for these agreements, which have remaining terms of approximately four to fifteen years, is approximately $1.5 billion, undiscounted. The agreements relate to firm transportation commitments on certain pipelines which were placed into service in late 2017 and early 2018 or to services on new pipeline projects to be constructed by, and connected to, existing and new interstate pipeline systems, with estimated in-service dates in December 2018. The contracts with estimated fourth quarter 2018 in-service dates represent approximately $925 million, undiscounted, of the total undiscounted commitment of approximately $1.5 billion.

In 2017, we accrued non-cash exit costs totaling $93 million, discounted, relating to:

- $41 million, discounted, for a retained transportation contract for a pipeline project that is in service; however, we no longer have production to satisfy this commitment and we do not have plans to utilize this capacity in the future; and
- $52 million, discounted, for future commitments to a third party who assumed a portion of our retained capacity relating to pipeline projects that were placed into service.

The non-cash exit costs were included in loss on Marcellus Shale exit activities in our consolidated statements of operations in 2017 in accordance with accounting for exit or disposal activities under ASC 420, *Exit or Disposal Cost Obligations*.

The change in the Marcellus Shale firm transportation commitment, discounted, is as follows:

(millions)	September 30, 2018	December 31, 2017
Balance at Beginning of Period	$ 90	$ —
Firm Transportation Accrual	—	93
Payments	(9)	(3)
Balance at End of Period	$ 81	$ 90
Less Current Portion Included in Other Current Liabilities	12	14
Long-term Portion Included in Other Noncurrent Liabilities	$ 69	$ 76

We are currently engaged in efforts to commercialize these firm transportation commitments which provide for the transportation of 450,000 MMBtu/d of natural gas. Efforts include the permanent assignment of capacity, negotiation of capacity release, utilization of capacity through purchase of third party natural gas, and other potential arrangements. Beginning in first quarter 2018, we entered into purchase transactions of third party natural gas and separate sale transactions to other third parties at prevailing market prices to mitigate these firm transportation commitments. Revenues and expenses from these transactions are recorded on a gross basis, as we act as a principal in these arrangements by assuming control of the purchased commodity before it is transferred to the customer.

The components of revenues and expenses associated with these transactions are as follows:

		Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	Statements of Operations Location	2018	2017	2018	2017
Sales of Purchased Gas	Sales of Purchased Oil and Gas and Other	$ 26	$ —	$ 81	$ —
Cost of Purchased of Gas	Other Operating Expense (Income), Net	$ 24	$ —	$ 77	$ —
Firm Transportation Expense	Other Operating Expense (Income), Net	7	—	18	—
Unutilized Firm Transportation Expense	Other Operating Expense (Income), Net	1	—	3	—
Purchased Gas, Total	Other Operating Expense (Income), Net	$ 32	$ —	$ 98	$ —
Sales of Purchased Gas, Net		$ (6)	$ —	$ (17)	$ —

We expect to continue our commercialization actions, including utilizing pipeline capacity through purchase transactions of third party natural gas and separate sale transactions to other third parties, to mitigate these firm transportation commitments. Some of our commercialization efforts may require pipeline and/or FERC approval to ultimately reduce our 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. We cannot guarantee our commercialization efforts will be successful and we may recognize substantial future liabilities. See Note 2. Basis of Presentation and Note 3. Acquisitions and Divestitures.

Note 13. 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.

Colorado Air Matter In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency (EPA), 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 US District Court for the District of Colorado 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 corrective actions, to complete mitigation projects, to complete supplemental environmental projects (SEP), and to pay a civil penalty. Costs associated with the settlement consist of $5 million in civil penalties, which were paid in 2015. Mitigation costs of $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. Since 2015, we have incurred approximately $83 million to undertake corrective actions 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, plugging and abandonment activities, and mitigation expenditures that result from this settlement, based on currently available information, will not have a material adverse effect on our financial position, results of operations or cash flows. See Note 8. Asset Retirement Obligations.

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 Oil and Gas Conservation Commission Administrative Order on Consent In July 2018, we resolved by Administrative Order on Consent (AOC) with the Colorado Oil and Gas Conservation Commission (COGCC) allegations of noncompliance associated with site preparation and stabilization at an oil and gas location in Weld County, Colorado. The AOC required us to pay an administrative penalty of $135 thousand ($41 thousand of which is deferred subject to a nine-month compliance schedule) and to complete certain corrective actions at five oil and gas locations in Weld County, Colorado. We have concluded that the resolution of this action did not have a material adverse effect on our financial position, results of operations or cash flows.

Colorado Mechanical Integrity Testing Matter In September 2018, we resolved by AOC with the COGCC administrative claims for allegations of noncompliance of State mechanical integrity testing rules at eight shut-in wells in Weld County, Colorado. The AOC includes an administrative penalty of $1.6 million, of which $1.4 million of the total penalty is to be offset by our commensurate contribution to two public projects and requires us to repair or plug and abandon each of the eight wells and to submit to COGCC certain environmental data. We have concluded that the resolution of this action did not have a material adverse effect on our financial position, results of operations or cash flows.

Colorado Clean Water Act Referral Notice In September 2018, we received a letter from the US Department of Justice providing notification of referral from the EPA of alleged Clean Water Act violations at an upstream production facility and a midstream gathering facility in Weld County, Colorado. The letter requests an opportunity to discuss settlement of the alleged violations. Given the uncertainty associated with enforcement 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.

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:

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 2018. This discussion should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2017, which includes disclosures regarding our critical accounting policies as part of "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Operational Environment Update

Since 2016, commodity prices have steadily increased driven partially by the rebalancing of global supply and demand. As commodity prices have strengthened, the demand for oilfield services and infrastructure, particularly in US onshore basins, has risen, leading to cost inflation for the drilling, completion and operating of wells, and for the construction and/or access to necessary oil and gas infrastructure. As a result, there is pressure on operating margins and capital efficiency in US onshore basins, including those in which we operate. While we cannot fully offset the effects of these cost pressures, we have focused on a number of efficiency initiatives. For example, in the Delaware Basin, we have moved from single well development to multi-well pads, transitioned to row-style development designs, which we have utilized in both the DJ Basin and Eagle Ford Shale, and are primarily sourcing local sand for completions. In the DJ Basin, we have continued to expand our water recycling infrastructure and optimize our basin position through acreage exchanges leading to capital economies of scale, and have progressed optionality for midstream processing, compression and offload availability in the basin to take advantage of higher commodity prices.

With increased commodity prices and the recent resurgence of US onshore drilling activity, demand has increased for access to gathering facilities, transportation and/or takeaway pipelines due to growing production volumes. Transportation bottlenecks or infrastructure limitations caused by the increased utilization may lead to competitive pricing pressures in certain basins. As a result of location-basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period. In the Delaware Basin, midstream suppliers are working to construct new gathering, transportation and processing facilities or to repurpose existing infrastructure in an effort to proactively outpace expected production growth. Given the current level of takeaway capacity from the Delaware Basin to other markets, we have deferred some of our completion activity in the near-term to align with the timing of additional takeaway capacity that will become available in the future. In this regard, we have secured near-term flow assurance and long-term out-of-basin takeaway from the Delaware Basin to the Gulf Coast, with access to export markets. This includes the EPIC firm transport agreement that will provide 100 MBbl/d of gross crude oil takeaway capacity from the Delaware Basin to the Gulf Coast beginning in late 2019.

In order to mitigate the effect of commodity price volatility and enhance the predictability of our cash flows, we have entered into crude oil and natural gas price hedging arrangements. While these instruments mitigate the cash flow risk of future decreases in commodity prices, they have curtailed some of the benefit from current crude oil price increases and we have made year to date cash settlements of $160 million.

Against this backdrop of increasing commodity prices and rising costs, we remain committed to funding our shareholder return initiatives and have repurchased $233 million of common stock to date, as well as approved dividend increases for second, third and fourth quarter 2018. See Liquidity and Capital Resources.

Recent Achievements

Since 2015, we have strategically repositioned our portfolio to focus capital investment primarily in US onshore plays, including the DJ and Delaware Basins and Eagle Ford Shale, and on our international offshore assets in the Eastern Mediterranean and West Africa. The focus of our capital programs in these areas is expected to positively impact our future cash flows and margins. Going forward, we are concentrating our exploration capabilities on higher-impact opportunities that can drive substantial long-term value creation.

During third quarter 2018, we continued to progress our US onshore drilling and completions activities and advanced our Eastern Mediterranean and West Africa regional natural gas developments. Third quarter 2018 achievements included the following:

Sales Volumes We delivered quarterly sales volumes of 345 MBoe/d with approximately 55% of our production mix attributable to crude oil and NGLs. Reported volumes reflect the impact of adoption of ASC 606, *Revenue from Contracts with Customers* (ASC 606). See Exploration and Production (E&P) – Results of Operations.

Transportation Agreements to Deliver Natural Gas to Egypt In September 2018, we announced the execution of multiple agreements to support delivery of natural gas from the Leviathan and Tamar fields into Egypt through existing infrastructure. With these agreements, we have secured capacity to deliver on our firm natural gas sales agreement for Leviathan, while also allowing for interruptible sales from Tamar into Egypt. Certain conditions must occur prior to closing the agreements, which is currently expected in early 2019. See Exploration and Production (E&P) – Development Projects.

CNX Midstream Partners Unit Sale During third quarter 2018, we sold 14.2 million common units, representing our remaining 22.3% limited partner interest in CNX Midstream Partners. We received net proceeds of approximately $248 million, net of placement agent fees, and recognized a gain of $198 million. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Noble Midstream Services Term Loan Credit Facility On July 31, 2018, Noble Midstream Services, LLC (Noble Midstream Services) entered into an agreement providing for a three year senior unsecured term loan credit facility (Noble Midstream Services Term Loan Credit Facility) of up to $500 million and used amounts received to pay down the Noble Midstream Services Revolving Credit Facility. See Item 1. Financial Statements – Note 5. Debt.

Hedging Activities We entered into natural gas basis swap contracts for 2019 in order to establish a fixed amount for the differential between index pricing for Colorado Interstate Gas and NYMEX Henry Hub, thus mitigating the price risk associated with our DJ Basin production. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

Share Repurchases In accordance with the $750 million share repurchase program authorized by our Board of Directors earlier this year, we repurchased and retired 3.4 million shares of common stock at an average purchase price of $30.07 per share during third quarter 2018.

Financial Flexibility, Liquidity and Balance Sheet Strength As we progress through the remainder of 2018, 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 continue to evaluate the commodity price environment, well productivity and efficiency gains in aligning our activity levels with current commodity price conditions. To this end, our 2018 capital investment program is responsive to positive or negative commodity price conditions that may develop. See Operating Outlook – 2018 Capital Investment Program.

If commodity prices decline or operating costs continue 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, stock repurchase program or dividends, asset sales or operating cost structure. Our production and our stock price could decline as a result of these potential developments.

Subsequent Events

Sale of Tamar Petroleum Ltd. Shares We sold our investment in shares of Tamar Petroleum Ltd. (Tamar Petroleum) in two separate transactions on October 2 and October 3, 2018, for total pre-tax proceeds of $163 million, net of expenses. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Noble Midstream Partners Salt Creek Joint Venture During third quarter 2018, we progressed commercialization options in the Delaware Basin for midstream expansion and, in early October 2018, Noble Midstream Partners LP (Noble Midstream Partners) entered into a letter of intent with Salt Creek Midstream LLC (Salt Creek) to form a 50/50 joint venture to construct a crude oil pipeline and gathering system. The transaction is expected to close in fourth quarter 2018.

Adoption of ASC 606

As of January 1, 2018, we adopted ASC 606*,* using the modified retrospective method. ASC 606 adoption did not have an impact on the opening balance of retained earnings. The adoption resulted in a de minimis decrease of $2 million to revenues and expenses for third quarter 2018 and an increase of $5 million to revenues and expenses for first nine months of 2018, respectively, but did not affect operating or net income or operating cash flows. Comparative information for the prior periods has not been recast and continues to be reported under the accounting standards in effect for those periods. Adoption of the new standard did not impact our financial position and we do not expect that it will going forward. See Exploration and Production (E&P) – Results of Operations.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2018 Capital Investment Program

Our 2018 capital investment program is designed to deliver near and long-term value and is flexible in the current commodity price environment. Excluding capital funded by Noble Midstream Partners, our initial 2018 program accommodated an investment level of approximately $2.7 to $2.9 billion and was contemplated using a West Texas Intermediate price assumption of $50 per barrel. In second quarter 2018, we revised our capital program to accommodate an investment level of approximately $3.0 billion, reflecting increased onshore facility spend from the first half of 2018 and cost inflation in US onshore as a result of the higher commodity price environment.

Approximately 95% of the capital program is being allocated to US onshore development, associated midstream infrastructure, the Eastern Mediterranean and spending to advance natural gas monetization in West Africa. In addition, given industry take-away constraints in the Delaware Basin, we have reduced some near-term investment. This will ensure that we are optimizing our development plans and timing our Delaware Basin activity to benefit from necessary takeaway infrastructure planned for next year.

The remaining portion of the capital program is designated for other activities, including lease acquisition, seismic and other geological analysis in support of future exploration prospects, as well as other corporate activities.

We will continue to evaluate the level of capital spending throughout the year based on the following factors, among others, and their effect on project financial returns:

- commodity prices, including price realizations on specific crude oil, natural gas and NGL production;
- operating and development costs;
- production, drilling and delivery commitments, or other contractual obligations;
- access and availability of gathering, transportation, takeaway and processing capacity for US onshore production volumes;
- drilling results;
- property acquisitions and divestitures;
- exploration activity;
- cash flows from operations;
- indebtedness levels;
- availability of financing or other sources of funding;
- impact of new laws and regulations on our business practices, including potential legislative or regulatory changes regarding the use of hydraulic fracturing; and
- potential changes in the fiscal regimes of the US and other countries in which we operate.

See Liquidity and Capital Resources – Financing Activities.

Colorado Proposition #112

In the state of Colorado, initiatives have been underway to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations. On November 6, 2018, Colorado voters will decide whether to adopt Proposition #112, which, if passed, could significantly limit, or in some cases prevent, the future development of crude oil and natural gas in areas where we currently conduct operations. Moreover, Proposition #112 could simultaneously curtail demand for our midstream services within the state. As such, our future drilling activities in Colorado could be significantly limited or hindered, and the amounts that we are ultimately able to produce from our undeveloped reserves in Colorado could be adversely affected.

In addition, if Proposition #112 is adopted, or other regulatory measures go into effect, we may incur additional costs to comply with any of its requirements or may experience delays and/or curtailment in the permitting or pursuit of our exploration, development, or production activities. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our cash flows, results of operations, financial condition, and liquidity. Adoption of Proposition #112 could result in a decrease in our proved undeveloped reserves and even a material impairment of our Colorado assets. See Part II. Other Information - Item IA. Risk Factors.

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

Regulatory Update

During the first nine months of 2018, the US Administration imposed import tariffs of 25% on steel products and 10% on aluminum products, as well as quantitative restrictions on imports of steel and/or aluminum products from various countries. More recently in August 2018, the US Administration permitted relief from these quotas including relief on steel quotas from Argentina, Brazil, and South Korea and on aluminum from Argentina. The US oil and gas industry relies on steel for drilling and completion of new wells, as well as for facility production at refineries, petrochemical plants and pipelines. Much of the steel required is in the form of specialty steel products, manufactured to exact specifications, and may not be available domestically in sufficient quantities.

Implementation of these tariffs will likely increase prices for specialty and other products used in various aspects of upstream, midstream and downstream activities. Furthermore, the tariffs and quantitative restrictions may cause disruption in the energy industry’s supply chain, resulting in delay or cessation of drilling efforts or postponement or cancellation of new inter- or intra-state pipeline projects that the industry is relying on to transport its increasing onshore production to market, as well as endangering US liquefied natural gas (LNG) export projects resulting in negative impacts on natural gas production.

In addition, countries subject to the tariffs and/or import restrictions have threatened to retaliate and/or have recently imposed tariffs on American products, resulting in escalating trade disputes with certain trade partners. Trade and/or tariff disputes could result in increased costs or shortages of materials and supplies the industry relies on to produce, process and transport its oil and gas production. Moreover, trade and/or tariff disputes could have negative impacts on the US and global economies overall and could result in less demand for our products.

EXPLORATION AND PRODUCTION (E&P)

We continue to advance our major development projects, which we expect to deliver incremental production and cash flows over the next several years.

Sanctioned Ongoing Development Projects

A "sanctioned" development project is one for which a final investment decision has been reached. Updates on major development projects are as follows:

DJ Basin (US Onshore) Our activities during third quarter 2018 were focused primarily in the Mustang integrated development plan (IDP) area, where we have a large contiguous acreage position. Our development plan in this area includes applying multiple techniques from our other successful US onshore plays, including utilizing row development concepts, enhanced completion designs, capital-efficient facility designs, and other techniques to optimize project returns. Aiding our development plan is the fact that we have access to existing infrastructure and multiple natural gas processing facilities to support processing capacity and growth from the field. During the quarter, we operated two drilling rigs, completed 24 wells and commenced production on 37 wells. Average sales volumes during third quarter 2018 were 126 MBoe/d, including 11 MBoe/d due to ASC 606 adoption.

Delaware Basin (US Onshore) During third quarter 2018, we operated an average of six drilling rigs, completed 22 wells and commenced production on 20 wells, with the majority of our activity focused on long laterals and multi-well pads targeting multiple zones within the basin. We averaged 58 MBoe/d of sales volumes during third quarter 2018, with approximately 66% of our production mix attributable to crude oil.

As part of the EPIC strategic relationship, we secured options to acquire up to 30% ownership interest in the company that owns the EPIC crude oil pipeline. In addition, Noble Midstream Partners secured an option to acquire up to 15% ownership interest in the company that owns the EPIC NGL pipeline. We are evaluating both options which expire in first quarter 2019.

In June 2018, we supplemented our Delaware Basin takeaway position with an additional firm sales agreement, which results in our crude oil reaching the Gulf Coast. The five-year agreement provides for firm gross sales of at least 10 MBbl/d of crude oil that began in July 2018 and increased to 20 MBbl/d beginning in October 2018 for the remainder of the agreement. Crude oil sold under the agreement is initially utilizing the buyer's existing firm transport capacity to Corpus Christi. For a period of 10-years following commencement of full service of the EPIC crude oil pipeline in 2019, it is anticipated that crude oil sales under the agreement will be transported by way of our firm transportation capacity. We previously executed firm sales agreements to the Texas Gulf Coast or Cushing, Oklahoma markets for Delaware Basin crude oil covering gross oil volumes of 10 MBbl/d for the second half of 2018 and 5 MBbl/d for 2019.

Eagle Ford Shale (US Onshore) During third quarter 2018, we operated one to two drilling rigs and completed three wells, primarily focused within the Upper and Lower Eagle Ford formation zones. In addition, we continued construction of a central delivery facility in the northern area of Gates Ranch which will provide separation and compression capabilities for our multi-well completion program beginning in fourth quarter 2018 and into 2019. We continue to execute our development plan and averaged sales volumes of 65 MBoe/d during third quarter 2018.

Tamar Natural Gas Project (Eastern Mediterranean) In third quarter 2018, offshore Israel sales volumes averaged 242 MMcfe/d, net, and on a gross basis, sales volumes reached a cumulative milestone delivering 1.7 Tcf of natural gas to-date. Third quarter gross sales volumes established a quarterly production record of nearly 1.1 Bcfe/d, driven by continued coal displacement in power generation and increased demand for electricity. As customer demand increases and to reinforce the reliability of the Tamar project, we have continued to progress regulatory approval with the Government of Israel regarding the development plan for our 2013 Tamar Southwest discovery.

Leviathan Natural Gas Project (Eastern Mediterranean) 2018 represents the peak year for capital investments for the initial phase of the Leviathan development, offshore Israel. The project is now nearly 67% complete and remains on budget and on schedule. We have installed the in-field gathering and export pipelines, completed installation of all subsea trees, finished completions on the Leviathan 3 and 4 wells with successful flowbacks and completed the float of the main decks and jacket rollup. First natural gas sales are anticipated by the end of 2019.

Leviathan and Tamar Natural Gas Transportation Agreements (Eastern Mediterranean) In September 2018, we announced the execution, along with certain third-parties, of agreements to support delivery of natural gas from the Leviathan and Tamar fields, offshore Israel, to customers in Egypt. With certain partners, we expect to acquire a 39% equity interest in Eastern Mediterranean Gas Company S.A.E., which owns the EMG Pipeline. We will own an effective, indirect interest of approximately 10% in the pipeline and, along with our partners, will enter into an agreement to exclusively operate the pipeline, securing access to the pipeline's full capacity.

Our estimated acquisition cost for our interest in the pipeline is approximately $200 million, due at closing. Initial natural gas delivery through the EMG Pipeline is expected from the Tamar field under our existing interruptible natural gas sales agreement. Upon startup of the Leviathan field by the end of 2019, we anticipate selling at least 350 MMcf/d of natural gas, gross, to contracted customers in Egypt. Closing of the agreement is subject to fulfillment of certain conditions precedent, which is expected in early 2019. These conditions include gaining regulatory and government approvals, obtaining third-party recertification of the pipeline, completing the due diligence process and confirming sustained gas flow. Additionally, technical evaluation and flow reversal planning is ongoing.

We also received a letter of intent from the owner of the El Arish Pipeline to secure an option for additional capacity to transport natural gas within Egypt. This agreement will support transportation of natural gas to Egypt in addition to quantities supplied through the EMG Pipeline.

Unsanctioned Development Projects

West Africa Natural Gas Monetization We continue 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 and progress negotiations of required contracts. In May 2018, we announced the execution, along with the Government of the Republic of Equatorial Guinea and necessary third-parties, of a Heads of Agreement establishing the framework for development of natural gas from the Alen field. The agreement outlines the high-level commercial terms for Alen natural gas to be processed through Alba Plant LLC’s liquefied petroleum gas (LPG) plant and Equatorial Guinea LNG Holdings Limited’s LNG plant. Both plants are located in Punta Europa. The contemplated structure would result in Alen natural gas being marketed to global LNG markets. Sanction of the project is contingent upon final commercial agreements being executed.

Existing production and processing facilities in place at the Alen platform and in Punta Europa require certain modifications to produce and process the Alen natural gas. The agreement contemplates construction of a 65-kilometer pipeline to transport natural gas from the Alen platform to the facilities in Punta Europa. We have awarded front-end engineering design (FEED) activities to progress the project to final investment decision, which is expected in first quarter 2019.

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 regional customers. In addition, we are focused on capital cost improvements, as well as 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.

Exploration Program Update

We continue to seek and evaluate significant onshore and/or offshore opportunities for future exploration. 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 expensed and included in dry hole costs.

Additionally, we may not be able to conduct exploration activities prior to lease expirations or may choose to relinquish or exit licenses. For example, in October 2018, we began the process of exiting our remaining PL-001 license, which includes the Rhea prospect, offshore Falkland Islands. While leasehold abandonment expense associated with this exit is de minimis, other exploration opportunities in a future period could result in significant dry hole cost and/or leasehold abandonment expense. See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Results of Operations

Highlights for our E&P business were as follows:

Third Quarter 2018 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 345 MBoe/d, net;
- record average daily sales volumes for US onshore crude oil of 109 MBbl/d, net; and
- record average daily sales volumes of approximately 1.1 Bcfe/d, gross, offshore Israel, primarily from the Tamar field.

Third Quarter 2018 E&P Financial Results Included:

- total loss of $155 million on commodity derivative instruments;
- pre-tax income of $225 million, as compared with pre-tax income of $41 million for third quarter 2017; and
- capital expenditures, excluding acquisitions, of $696 million, as compared with $596 million for third quarter 2017.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2018	2017	2018	2017
Oil, NGL and Gas Sales to Third Parties [1]	$ 1,136	$ 907	$ 3,409	$ 2,918
Sales of Purchased Gas [2]	26	—	81	—
Income from Equity Method Investees	34	33	105	84
Total Revenues	1,196	940	3,595	3,002
Production Expense [1]	316	316	997	953
Exploration Expense	25	64	89	136
Depreciation, Depletion and Amortization	456	502	1,336	1,502
Purchased Gas [2]	32	—	98	—
Loss on Marcellus Shale Exit Activities	—	4	—	2,326
Loss (Gain) on Divestitures, Net [3]	5	—	(356)	—
Asset Impairments [4]	—	—	168	—
Loss (Gain) on Commodity Derivative Instruments	155	22	483	(145)
Gain on Investment in Shares of Tamar Petroleum Ltd., Net [5]	(32)	—	(6)	—
Clayton Williams Energy Acquisition Expenses	—	4	—	98
Income (Loss) Before Income Taxes	225	41	720	(1,944)

(1) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of certain US midstream processing arrangements related to net and gross presentation of revenues and expenses. This presentation change resulted in a decrease of $2 million to revenues and production expense for third quarter 2018 and an increase of $5 million to revenues and production expense for first nine months of 2018, respectively. See Item 1. Financial Statements – Note 2. Basis of Presentation.

(2) Beginning in first quarter 2018, as part of our Marcellus Shale firm transportation mitigation efforts, we entered into certain transactions for the purchase of third party natural gas and the subsequent sale of natural gas to other third parties. See Item 1. Financial Statements - Note 12. Marcellus Shale Firm Transportation Contracts and *Sales of Purchased Gas*, *Net* below.

(3) Amount for the nine months ended September 30, 2018, includes a gain of $376 million on the sale of a 7.5% interest in the Tamar field, offshore Israel.

(4) Amount relates to the Gulf of Mexico asset sale. See Item 1. Financial Statements - Note 3. Acquisitions and Divestitures.

(5) Amounts for third quarter and first nine months of 2018 include a gain of $15 million and a loss of $25 million, respectively, due to changes in the fair value of our investment in shares of Tamar Petroleum Ltd. In addition, amounts for third quarter and first nine months of 2018 include dividend income of $17 million and $31 million, respectively. The shares in Tamar Petroleum were sold in two separate transactions on October 2 and October 3, 2018, for pre-tax proceeds of $163 million, net of transaction expenses. See Item 1. Financial Statements - Note 3. Acquisitions and Divestitures and Item 1. Financial Statements - Note 6. Fair Value Measurements and Disclosures.

Oil, NGL and Gas Sales

Average daily sales volumes and average realized sales prices, which exclude gains and losses related to commodity derivative instruments, were as follows:

	Sales Volumes [1]				Average Realized Sales Prices [1]		
	Crude Oil & Condensate (MBbl/d)	NGLs (MBbl/d)	Natural Gas (MMcf/d)	Total (MBoe/d) [2]	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended September 30, 2018							
United States	109	63	464	249	$ 65.54	$ 28.58	$ 2.31
Eastern Mediterranean	—	—	241	41	—	—	5.49
West Africa [3]	13	—	217	49	73.70	—	0.27
Total Consolidated Operations	122	63	922	339	66.41	28.58	2.66
Equity Investees [4]	1	5	—	6	74.88	48.27	—
Total	123	68	922	345	$ 66.50	$ 29.92	$ 2.66
Three Months Ended September 30, 2017							
United States	114	56	449	244	$ 46.63	$ 22.88	$ 2.23
Eastern Mediterranean	—	—	283	48	—	—	5.36
West Africa [3]	13	—	246	54	51.32	—	0.27
Total Consolidated Operations	127	56	978	346	47.13	22.88	2.65
Equity Investees [4]	2	7	—	9	52.69	37.49	—
Total	129	63	978	355	$ 47.27	$ 24.56	$ 2.65
Nine Months Ended September 30, 2018							
United States [5]	113	63	479	255	$ 63.98	$ 26.22	$ 2.42
Eastern Mediterranean	—	—	242	41	—	—	5.48
West Africa [3]	15	—	216	51	71.55	—	0.27
Total Consolidated Operations	128	63	937	347	64.86	26.22	2.71
Equity Investees [4]	2	5	—	7	72.46	43.70	—
Total	130	68	937	354	$ 64.95	$ 27.50	$ 2.71
Nine Months Ended September 30, 2017							
United States	108	56	637	270	$ 47.07	$ 21.66	$ 3.06
Eastern Mediterranean	—	—	276	46	—	—	5.33
West Africa [3]	18	—	240	58	51.29	—	0.27
Total Consolidated Operations	126	56	1,153	374	47.66	21.66	3.02
Equity Investees [4]	1	6	—	7	51.72	36.23	—
Total	127	62	1,153	381	$ 47.75	$ 23.07	$ 3.02

(1) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of certain US midstream processing arrangements as related to net and gross presentation of revenues and expenses. See Item 1. Financial Statements – Note 2. Basis of Presentation. This presentation change resulted in the following:

- decrease in NGL revenues, and corresponding decrease in production expense, of $1 million for third quarter 2018 and increase in NGL revenues, and corresponding increase in production expense, of $8 million for the first nine months of 2018;
- decreases in natural gas revenues, and corresponding decreases in production expense, of $1 million and $3 million for third quarter and first nine months of 2018, respectively;
- increases in NGL and natural gas sales volumes of 5 MBbl/d and 31 MMcf/d, respectively, for both third quarter and first nine months of 2018, respectively; and
- reductions in average realized NGL and natural gas sales prices of $2.67/Bbl and $0.10/Mcf, respectively, for third quarter 2018 and $1.61/Bbl and $0.10/Mcf, respectively, for the first nine months of 2018.

(2) 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 prices 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.
(3) Natural gas from the Alba field in Equatorial Guinea is sold under contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.
(4) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea. See *Income from Equity Method Investees,* below.
(5) Includes 9 MBoe/d for first nine months of 2018 related to Gulf of Mexico assets sold in April 2018. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	NGLs	Natural Gas	Total
Three Months Ended September 30, 2017	$ 553	$ 116	$ 238	$ 907
Changes due to				
(Decrease) Increase in Sales Volumes	(28)	8	(28)	(48)
Increase in Sales Prices (1)	219	43	17	279
Impact of ASC 606 Adoption	—	(1)	(1)	(2)
Three Months Ended September 30, 2018	$ 744	$ 166	$ 226	$ 1,136
Nine Months Ended September 30, 2017	$ 1,637	$ 329	$ 952	$ 2,918
Changes due to				
Increase (Decrease) in Sales Volumes	20	10	(218)	(188)
Increase (Decrease) in Sales Prices (1)	609	102	(37)	674
Impact of ASC 606 Adoption	—	8	(3)	5
Nine Months Ended September 30, 2018	$ 2,266	$ 449	$ 694	$ 3,409

(1) Changes exclude gains and losses related to commodity derivative instruments. See Item 1. Financial Statements - Note 4. Derivative Instruments and Hedging Activities for gains and losses and cash paid (received) in settlement of commodity derivative instruments for the periods presented.

Crude Oil and Condensate Sales Revenues Revenues from crude oil and condensate sales increased third quarter and first nine months of 2018 as compared with 2017 due to the following:

- increases of 41% and 36% for third quarter and first nine months of 2018, respectively, in average realized prices due to the partial rebalancing of global supply and demand factors and exposure to Brent pricing in West Africa; and
- higher US onshore sales volumes of 16 MBbl/d and 20 MBbl/d for third quarter and first nine months of 2018, respectively, primarily driven by an increase in development activity in the Delaware and DJ Basins;

partially offset by:

- lower Gulf of Mexico sales volumes of 21 MBbl/d and 15 MBbl/d for third quarter and first nine months of 2018, respectively, due to natural field decline as well as the sale of the Gulf of Mexico assets in second quarter 2018; and
- lower offshore Equatorial Guinea sales volumes of 3 MBbl/d for first nine months of 2018 due to natural field decline.

NGL Sales Revenues Revenues from NGL sales increased third quarter and first nine months of 2018 as compared with 2017 due to the following:

- higher US onshore sales volumes of 4 MBbl/d (exclusive of 5 MBbl/d from adoption of ASC 606) and 10 MBbl/d (exclusive of 5 MBbl/d from adoption of ASC 606) for third quarter and first nine months of 2018, respectively, primarily attributable to development activities in the Delaware and DJ Basins;
- increases of 37% and 29% in average realized prices for third quarter and first nine months of 2018, respectively, due to the partial rebalancing of domestic supply and demand factors; and
- an increase of $8 million for the first nine months of 2018 associated with the adoption of ASC 606;

partially offset by:

- a decrease of $1 million for third quarter 2018 associated with the adoption of ASC 606; and
- lower sales volumes of 6 MBbl/d for first nine months of 2018 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 and first nine months of 2018 as compared with 2017 due to the following:

- lower sales volumes of 232 MMcf/d for the first nine months of 2018 due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;
- lower Gulf of Mexico sales volumes of 20 MMcf/d and 12 MMcf/d for third quarter and first nine months of 2018, respectively, due to natural field decline as well as the sale of the Gulf of Mexico assets in second quarter 2018;
- lower Israel sales volumes of 44 MMcf/d and 36 MMcf/d for third quarter and first nine months of 2018, respectively, primarily due to the sale of a 7.5% interest in the Tamar field in second quarter 2018;
- lower sales volumes of 29 MMcf/d and 24 MMcf/d for third quarter and first nine months of 2018, respectively, from the Alba field, offshore Equatorial Guinea, due to natural field decline and timing of field maintenance; and
- decreases in average realized prices for the first half of 2018 due to the impact of increased onshore US supply, as well as wider summer price differentials for both DJ and Delaware Basin volumes;

partially offset by:

- increase of 4% in average realized prices for third quarter 2018 due to to low natural gas inventory levels and positive developments in the LNG markets signaling a potential increase in global demand;
- higher US onshore sales volumes of 12 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606) and 63 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606) for third quarter and first nine months of 2018, respectively, primarily attributable to development activities in the Delaware and DJ Basins; and
- higher sales volumes related to our remaining working interest in Israel due to increased demand for power as well as conversion of facilities from use of coal to natural gas.

Sales of Purchased Gas, Net Beginning in first quarter 2018, we entered into purchase transactions and separate sale transactions with third parties at prevailing market prices to mitigate unutilized pipeline transportation commitments, primarily related to retained Marcellus Shale natural gas firm transportation agreements. Revenues and expenses from the sales and purchases are recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. Transportation costs incurred related to utilization of the retained Marcellus Shale firm transportation agreements, as well as those costs related to unutilized Marcellus Shale firm transportation, are recorded within purchases of gas in our consolidated statements of operations. For third quarter and first nine months of 2018, the net effect of third party purchases and sales of natural gas were losses of $6 million and $17 million, respectively.

Income from Equity Method Investees Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported in sales of purchased oil and gas and other 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 2018 as compared with 2017. The increase includes a $12 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee, and a $9 million increase from Alba Plant, our LPG investee, all primarily driven by rising commodity prices.

Production Expense Components of production expense from our E&P operations were as follows:

(millions, except unit rate)	Total per BOE (1) (2)	Total	United States (2)	Eastern Mediter- ranean	West Africa
Three Months Ended September 30, 2018					
Lease Operating Expense (3)	$ 4.37	$ 136	$ 114	$ 7	$ 15
Production and Ad Valorem Taxes	1.48	46	46	—	—
Gathering, Transportation and Processing (4)	4.14	129	129	—	—
Other Royalty Expense	0.16	5	5	—	—
Total Production Expense	$ 10.15	$ 316	$ 294	$ 7	$ 15
Total Production Expense per BOE		$ 10.15	$ 12.82	$ 1.90	$ 3.32
Three Months Ended September 30, 2017					
Lease Operating Expense (3)	$ 4.78	$ 152	$ 118	$ 9	$ 25
Production and Ad Valorem Taxes	0.94	30	30	—	—
Gathering, Transportation and Processing (4)	4.06	129	129	—	—
Other Royalty Expense	0.16	5	5	—	—
Total Production Expense	$ 9.94	$ 316	$ 282	$ 9	$ 25
Total Production Expense per BOE		$ 9.94	$ 12.58	$ 2.06	$ 5.00
Nine Months Ended September 30, 2018					
Lease Operating Expense (3)	$ 4.54	$ 429	$ 354	$ 19	$ 56
Production and Ad Valorem Taxes	1.55	147	147	—	—
Gathering, Transportation and Processing (4)	4.11	389	389	—	—
Other Royalty Expense	0.34	32	32	—	—
Total Production Expense	$ 10.54	$ 997	$ 922	$ 19	$ 56
Total Production Expense per BOE		$ 10.54	$ 13.22	$ 1.73	$ 4.04
Nine Months Ended September 30, 2017					
Lease Operating Expense (3)	$ 4.12	$ 420	$ 332	$ 23	$ 65
Production and Ad Valorem Taxes	1.00	102	102	—	—
Gathering, Transportation and Processing (4)	4.08	416	416	—	—
Other Royalty Expense	0.15	15	15	—	—
Total Production Expense	$ 9.35	$ 953	$ 865	$ 23	$ 65
Total Production Expense per BOE		$ 9.35	$ 11.76	$ 1.82	$ 4.12

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.
(2) United States E&P 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) Upon adoption of ASC 606 on January 1, 2018, we changed the presentation for certain of our gathering, transportation and processing expenses in accordance with the control model under the new standard. As such, we reflected a decrease of $2 million for third quarter 2018 and an increase of $5 million for first nine months of 2018, respectively, to gathering, transportation and processing expense related to US operations. On a per BOE basis, including the change in production volumes, the presentation change resulted in increases of $1.04/Boe and $0.89/Boe for total production expense for third quarter and first nine months of 2018, respectively, and decreases of $0.66/Boe and $0.57/Boe for US production expense for third quarter and first nine months of 2018, respectively. No other geographical locations were affected by the presentation change. Comparative information for the prior period has not been recast and continues to be reported under ASC 605, *Revenue Recognition*, the accounting standard in effect for the prior period.

Production expense for third quarter 2018 remained flat when compared with 2017, yet increased for first nine months of 2018 as compared with 2017 due to the following:

- an increase in US production and ad valorem taxes and in US other royalty expense due to higher commodity prices; and
- an increase in US lease operating expense, primarily due to increased development activities resulting in added production across each of our US onshore basins;

partially offset by:

- decreases in US lease operating and gathering, transportation and processing expenses in the Gulf of Mexico due to lower production caused by natural field decline and the subsequent sale of the assets in second quarter 2018;
- a decrease in lease operating expense in West Africa due to lower production caused by natural field decline; and
- decreases in US lease operating and gathering, transportation and processing expenses due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

The unit rate per BOE increased for the third quarter and first nine months of 2018, as compared with 2017, primarily due to the decrease in total sales volumes driven by divestitures of the Marcellus Shale upstream assets in second quarter 2017 and Gulf of Mexico assets in second quarter 2018, 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 contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE. In addition, the divestiture of the Gulf of Mexico assets in second quarter 2018 removed higher-cost, crude oil-focused sales volumes, which partially offset the increase in our average production expense per BOE.

Exploration Expense Exploration expense for the first nine months of 2018 totaled $89 million, including $32 million of lease rental expense primarily in the Delaware Basin and $41 million of staff expense. Exploration expense for the first nine months of 2017 totaled $136 million, including $51 million of undeveloped leasehold impairment expense primarily related to the impairment of leases in deepwater Gulf of Mexico, $40 million of staff expense, and $20 million of seismic, geological and geophysical expenses.

Depreciation, Depletion and Amortization Depreciation, depletion and amortization (DD&A) expense for our E&P operations was as follows:

(millions, except unit rate)	Total	United States	Eastern Mediter- ranean	West Africa	Other Int'l
Three Months Ended September 30, 2018					
DD&A Expense	$ 456	$ 414	$ 16	$ 25	$ 1
Unit Rate per BOE [1]	$ 14.64	$ 18.05	$ 4.34	$ 5.53	$ —
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	$ —
Nine Months Ended September 30, 2018					
DD&A Expense	$ 1,336	$ 1,214	$ 44	$ 77	$ 1
Unit Rate per BOE [1]	$ 14.12	$ 17.41	$ 4.00	$ 5.55	$ —
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	$ —

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

Total DD&A expense for third quarter and first nine months of 2018 decreased as compared with 2017 due to the following:

- year-end 2017 proved reserves additions, primarily in US onshore due to enhanced well design and completion techniques in our horizontal drilling program, in the Tamar field due to well results and geological evaluation, and globally due to positive commodity price revisions;
- lower sales volumes in Gulf of Mexico due to natural field decline and classification of the assets as held for sale in first quarter 2018, resulting in the cessation of DD&A expense, together resulting in decreases of $60 million and $169 million for third quarter and first nine months of 2018, respectively; and
- reclassification of a 7.5% working interest in the Tamar field, offshore Israel, as assets held for sale at December 31, 2017, resulting in the cessation of DD&A expense and decreases of $4 million and $11 million for third quarter and first nine months of 2018, respectively;

partially offset by:

- higher sales volumes in the Delaware Basin, which more than doubled, due to increased development activities subsequent to the Clayton Williams Energy Acquisition in second quarter 2017; and
- higher sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The unit rate per BOE for third quarter and first nine months of 2018 decreased, as compared with 2017, primarily due to the decrease in total DD&A expense combined with the sale of higher-cost production from the Gulf of Mexico assets in second quarter 2018. This decrease is partially offset by increased development activity in the Delaware Basin resulting in a higher depletable basis and the sales of lower-cost production from our 7.5% interest in the Tamar field in first quarter 2018 and the Marcellus Shale upstream assets in second quarter 2017.

Loss (Gain) on Divestitures, Net Loss (gain) on divestitures, net, relates primarily to the gain recognized on the first quarter 2018 sale of a 7.5% interest in the Tamar field, partially offset by the loss recognized on the sale of our Gulf of Mexico assets in second quarter 2018. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Other Operating Expense (Income), 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 (income) items for third quarter and first nine months of 2018 as compared with 2017.

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

For the first nine months of 2018, loss on commodity derivative instruments included:
- net cash settlement payment of $160 million; and
- net non-cash increase of $323 million in the fair value of our net commodity derivative liability, primarily driven by increases in the forward commodity price curve for crude oil.

For the first nine months of 2017, gain on commodity derivative instruments included:
- net cash settlement receipt of $18 million; and
- net non-cash increase of $127 million in the fair value of our net commodity derivative asset, primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities and Item 1. Financial Statements – Note 6. Fair Value Measurements and Disclosures.

MIDSTREAM

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

Recent Development

Noble Midstream Partners Salt Creek Joint Venture On October 2, 2018, Noble Midstream Partners entered into a letter of intent with Salt Creek to form a 50/50 joint venture on the construction of a 200 MBbl/d day pipeline system in the Delaware Basin. The 95-mile, 20-inch diameter pipeline system will originate in Pecos County, Texas, with additional connections in Reeves County and Winkler County, Texas. The project footprint will be served by a combination of in-field crude oil gathering lines and a trunkline to a hub in Wink, Texas.

Salt Creek has commenced construction of the pipeline, with an expected operational date in the second quarter of 2019. Execution of definitive agreements and closing of the transaction is expected to occur in the fourth quarter of 2018. At closing, the project will be underpinned by approximately 180,000 dedicated gross acres and nearly 100 miles of pipeline in Pecos, Reeves, Ward and Winkler Counties, Texas, including an in-basin crude oil dedication of approximately 70,000 gross acres by us. Capital investment from Noble Midstream Partners is expected to total approximately $60 million to $80 million over five years.

Results of Operations

Highlights for our Midstream segment were as follows:

Third Quarter 2018 Significant Midstream Operating Highlights and Financial Results Included:

- commenced gathering services on an initial well for a third-party Delaware Basin producer;
- net proceeds of approximately $248 million received, and gain of $198 million recognized, on the sale of our investment in CNX Midstream Partners common units;
- pre-tax income of $268 million, as compared with pre-tax income of $58 million for third quarter 2017; and
- capital expenditures of $69 million, as compared with $96 million for third quarter 2017.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2018	2017	2018	2017
Midstream Services Revenues – Third Party	$ 21	$ 7	$ 49	$ 12
Sales of Purchased Oil	46	—	110	—
Income from Equity Method Investees	10	13	35	41
Intersegment Revenues	91	72	257	198
Total Revenues	168	92	451	251
Operating Costs and Expenses	30	24	96	66
Depreciation and Amortization	24	10	62	20
Gain on Divestitures, Net	(198)	—	(503)	—
Purchased Oil	44	—	106	—
Total (Income) Expense	(100)	34	(239)	86
Income Before Income Taxes	$ 268	$ 58	$ 690	$ 165

Revenues 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 primarily affected by the level of drilling and completion activity in the areas of E&P operations and by changes in the supply of, and demand for, crude oil, natural gas, NGLs, and water in the markets served directly or indirectly by our midstream assets.

Total revenues for third quarter and first nine months of 2018 increased from 2017, primarily due to an increase in crude oil and produced water gathering services revenue and fresh water delivery revenue due to the commencement of services in the Greeley Crescent IDP area and Delaware Basin. In addition, fresh water delivery revenue increased due to the timing of well completion activity in the Mustang IDP area, and sales of purchased crude oil commenced in first quarter 2018 as a result of the Saddle Butte acquisition.

As part of the Saddle Butte acquisition in first quarter 2018, we acquired a large-scale integrated gathering system (Black Diamond gathering system) and associated third party contracts which include transactions for the purchase and sale of crude oil with varying counterparties. Revenues and expenses from the sales and purchases are recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. The purchases and sales of crude oil are at the prevailing market prices. For third quarter and the first nine months of 2018, the net impact on earnings of third party purchases and sales of crude oil was de minimis.

Operating Costs and Expenses Total operating expenses for third quarter and first nine months of 2018 increased from 2017, primarily due to an increase in gathering systems and facilities operating expense associated with the Billy Miner and Jesse James central gathering facilities, which commenced operations in the second half of 2017, the addition of expenses associated with the Black Diamond gathering system acquired in the Saddle Butte acquisition in first quarter 2018, and expenses associated with the commencement of gathering services in the Mustang IDP area during 2018.

Depreciation and amortization expense for third quarter and first nine months of 2018 increased from 2017 due to assets placed in service subsequent to third quarter 2017, including expense related to tangible and intangible assets acquired in the Saddle Butte acquisition during first quarter 2018.

Gain on Divestitures Gain on divestitures includes the first quarter 2018 sale of our interest in CONE Gathering and the second and third quarter 2018 sales of our investment in CNX Midstream Partners common units. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

CORPORATE

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except unit rate)	2018	2017	2018	2017
G&A Expense	$ 107	$ 102	$ 316	$ 304
Unit Rate per BOE (1)	$ 3.44	$ 3.21	$ 3.34	$ 2.98

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

G&A expense for third quarter and first nine months of 2018 increased as compared with 2017. This increase was driven primarily by increased employee and travel costs, campaign and government relations costs related to Colorado Proposition #112 and transaction costs related to the Saddle Butte acquisition in first quarter 2018. The increase in the unit rate per BOE for the third quarter and first nine months of 2018 as compared with 2017 was due primarily to the increase in total G&A expense combined with the decrease in total sales volumes due to the divestitures of the Marcellus Shale upstream assets in second quarter 2017 and Gulf of Mexico assets in second quarter 2018.

Loss (Gain) on Extinguishment of Debt, Net See Item 1. Financial Statements – Note 5. Debt for discussion of debt extinguishment activities for third quarter and first nine months of 2018 as compared with 2017.

Other Operating Expense (Income), 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 (income) items for third quarter and first nine months of 2018 as compared with 2017.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except unit rate)	2018	2017	2018	2017
Interest Expense, Gross	$ 88	$ 100	$ 269	$ 306
Capitalized Interest	(18)	(12)	(53)	(35)
Interest Expense, Net	$ 70	$ 88	$ 216	$ 271
Unit Rate per BOE (1)	$ 2.25	$ 2.77	$ 2.28	$ 2.66

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

Interest expense, gross, for third quarter and first nine months of 2018 decreased as compared with 2017, primarily due to a decrease in the overall debt balance. Specifically, subsequent to third quarter 2017, we repaid $550 million on our former Term Loan Facility due January 6, 2019, $379 million of Senior Notes due May 1, 2021 and $275 million, net, on our Revolving Credit Facility. In addition, in third quarter 2017, we conducted a tender offer and refinanced our 8.25% Senior Notes, resulting in a lower interest rate and lower interest expense, gross, for the first nine months of 2018 as compared with 2017. These financing activities were partially offset by an increase in Noble Midstream Partners debt of $350 million, which was primarily used to fund the first quarter 2018 Saddle Butte acquisition. See Item 1. Financial Statements - Note 5. Debt.

Capitalized interest for third quarter and first nine months of 2018 increased as compared with 2017, primarily due to higher work in progress amounts related to the Leviathan development.

The unit rate of interest expense, net, per BOE for third quarter and first nine months of 2018 decreased as compared with 2017, primarily due to the changes noted above, partially offset by the decrease in total sales volumes.

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 a sustained period of low prices. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a continuing exploration program and maintaining capacity to capitalize on financially attractive merger and acquisition opportunities. We endeavor to maintain a strong balance sheet and an 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, proceeds from divestitures of properties and other investments, and available borrowing capacity under our $4.0 billion unsecured revolving credit facility (Revolving Credit Facility). 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. We periodically consider repatriations of foreign cash to increase our financial flexibility and fund our capital investment program.

Our portfolio transformation strategy, primarily executed during 2017, has continued into 2018, with the sales of Gulf of Mexico assets, a 7.5% working interest in Tamar, our 50% interest in CONE Gathering LLC and our investment in CNX Midstream Partners common units. As a result, our divestitures have generated cash proceeds of approximately $3.8 billion during 2017-2018 and were used to improve our capital structure, fund a portion of our capital program, and strengthen our liquidity profile.

Thus far in 2018, we have funded our capital program through organic cash flows, proceeds from divestitures and, when needed, borrowings under our Revolving Credit Facility.

As of September 30, 2018, our outstanding debt (excluding capital lease obligations) totaled $6.4 billion. We may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness. In addition, we may from time to time seek to retire or purchase our outstanding senior notes through cash purchases in the open market, 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 significant.

Third Quarter and Year-to-Date 2018 Highlights

During third quarter 2018, we continued to focus efforts on shareholder return initiatives, including share repurchases and dividend growth with the following actions completed:

- acquisition of 3.4 million shares of Noble Energy stock, for $103 million, resulting in year to date repurchases of 7.4 million shares for $233 million, pursuant to the Board of Directors' authorized $750 million share repurchase program; and
- announcement in October 2018 of a November 2018 dividend of 11 cents per Noble Energy common share, which continues the 10% increase over 2017.

In addition, during the first nine months of 2018, we completed the following financing activities:

- redeemed $379 million in outstanding senior notes;
- repaid all amounts outstanding under the Revolving Credit Facility and extended its maturity date by two and a half years to March 2023;
- amended the Noble Midstream Services Revolving Credit Facility to increase the capacity from $350 million to $800 million and extended its maturity date by one and a half years to March 2023; and
- entered into the Noble Midstream Services Term Loan Credit Facility and subsequently borrowed $500 million, which was used to repay amounts outstanding under the Noble Midstream Services Revolving Credit Facility.

Also, during the first nine months of 2018, we repatriated $654 million from foreign operations with no US tax impact. Of the $654 million, $404 million was related to payments on an outstanding note payable that was fully repaid in second quarter 2018.

Available Liquidity

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

(millions, except percentages)	September 30, 2018	December 31, 2017
Total Cash [(1)]	$ 721	$ 713
Amount Available to be Borrowed Under Revolving Credit Facility [(2)]	4,000	3,770
Total Liquidity	$ 4,721	$ 4,483
Total Debt [(3)]	$ 6,676	$ 6,859
Noble Energy Share of Equity	10,346	9,936
Ratio of Debt-to-Book Capital [(4)]	39%	41%

(1) As of September 30, 2018, total cash included cash and cash equivalents of $17 million related to Noble Midstream Partners and $1 million restricted cash related to Noble Midstream Partners collateral on letters of credit. As of December 31, 2017, total cash included $18 million cash of Noble Midstream Partners and $38 million restricted cash related to the Saddle Butte acquisition that closed first quarter 2018.

(2) Excludes amounts available to be borrowed under the Noble Midstream Services Revolving Credit Facility and Leviathan Term Loan Facility, 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 and debt issuance costs. See Item 1. Financial Statements – Note 5. Debt.

(4) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount and issuance costs, 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 $720 million in cash and cash equivalents at September 30, 2018, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $440 million of this cash is attributable to our foreign subsidiaries. We do not expect to incur any significant US income tax expense with respect to future repatriation of foreign cash.

Revolving Credit Facilities Noble Energy's Revolving Credit Facility of $4.0 billion matures in 2023. The Noble Midstream Services Revolving Credit Facility of $800 million also matures in 2023. These facilities are used to fund capital investment programs and acquisitions and may periodically provide amounts for working capital purposes. At September 30, 2018, no amounts were outstanding under the Revolving Credit Facility and $50 million was outstanding under the Noble Midstream Services Revolving Credit Facility leaving $4.0 billion and $750 million in remaining availability under the respective credit facilities. See Item 1. Financial Statements – Note 5. Debt..

Noble Midstream Services Term Loan Credit Facility On July 31, 2018, Noble Midstream Services entered into the Noble Midstream Services Term Loan Credit Facility that permits aggregate borrowings of up to $500 million. See Item 1. Financial Statements – Note 5. Debt. As of September 30, 2018, $500 million was outstanding under this facility, which was used to repay amounts outstanding under the Noble Midstream Services Revolving Credit Facility.

Leviathan Term Loan Facility The Leviathan Term Loan Facility 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. 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, 2018, no amounts were drawn under this facility.

Legacy Rosetta Note Redemption In May 2018, we redeemed $379 million of Senior Notes due May 1, 2021, that we had assumed in the Rosetta Merger, for $395 million, including $11 million of accrued interest and $5 million of call premium. We fully amortized $10 million of remaining premium, and recognized a gain of $5 million for the unamortized premium.

Interest Rate Risk Certain of our borrowings subject us to interest rate risk. See Item 1. Financial Statements – Note 5. Debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Contractual Obligations

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, and we have executed major equipment and installation contracts in support of our development activities. As of September 30, 2018, we had entered into approximately $182 million, net, of contracts to support the remaining development activities 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, such as our Eagle Ford Shale and Delaware Basin properties, are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas, the amount of which could be substantial, or exercise options with land owners to extend leases. Failure to meet continuous development obligations or to exercise lease extensions may result in loss of leases.

EPIC Firm Transportation Agreement During second quarter 2018, we dedicated acreage to, and secured firm capacity with, EPIC Pipeline, LP for transport of 100 MBbl/d of crude oil from the Delaware Basin to Corpus Christi, Texas, for a 10-year period beginning at pipeline start-up, currently anticipated for fourth quarter 2019.

Marcellus Shale Firm Transportation Agreements We have remaining financial commitments of approximately $1.5 billion, undiscounted, associated with Marcellus Shale firm transportation contracts. We have engaged in actions to commercialize a substantial portion of these commitments, which provide for the transportation of approximately 450,000 MMBtu/d 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.

We expect these actions, some of which may require pipeline and/or FERC approval, to continue to reduce our financial commitment associated with these contracts. For pipelines currently under construction and targeted for in-service in December 2018, we will evaluate our position at the date each pipeline is placed in service and our commitment begins. 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. These contracts represent approximately $925 million, undiscounted, of the total $1.5 billion commitment noted above. See Item 1. Financial Statements – Note 12. Marcellus Shale Firm Transportation Contracts.

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:

	Nine Months Ended September 30,	
(millions)	2018	2017
Total Cash Provided By (Used in)		
Operating Activities	$ 1,776	$ 1,418
Investing Activities	(1,502)	(1,840)
Financing Activities	(266)	(224)
Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	$ 8	$ (646)

Operating Activities Cash provided by operating activities for the first nine months of 2018 increased $358 million as compared with 2017. Factors resulting in the increase included an increase in net revenues and a significant increase in the current portion of the commodity derivatives liability due to rising commodity prices, partially offset by higher production costs attributable to increased operational activity and rising costs in onshore US, and higher expenditures related to onshore US plugging and abandonment activities. In addition, we made cash settlements of $160 million for commodity derivatives, as compared with cash receipts of $18 million in the prior year.

Investing Activities Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for under 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.

Total additions to property, plant and equipment increased $633 million during the first nine months of 2018 as compared with 2017, primarily due to increases in spending related to development costs in the Delaware Basin, construction of midstream infrastructure and Leviathan development costs, partially offset by decreases in development costs in the Eagle Ford Shale and due to the divestitures of Marcellus Shale upstream and Gulf of Mexico assets. See Operating Outlook – 2018 Capital Investment Program, above.

During the first nine months of 2018, we completed certain portfolio activities including the Saddle Butte acquisition for $650 million, net of cash acquired. Also during the first nine months of 2018, we received net proceeds of $1.7 billion from asset sales, including the sale of our Gulf of Mexico assets, a 7.5% interest in the Tamar field, our 50% interest in CONE Gathering LLC and our interest in CNX Midstream Partners common units.

In comparison, during the first nine months of 2017, we used $637 million of cash, net of $21 million of cash acquired, to fund a portion of the consideration paid in the Clayton Williams Energy Acquisition and acquired Delaware Basin and other assets for $357 million. We received net cash proceeds of $1.0 billion from the Marcellus Shale upstream divestiture, and other investing activities provided net cash of $61 million.

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

Our primary financing activities during the first nine months of 2018 included a $230 million, net, Revolving Credit Facility repayment and $35 million, net, Noble Midstream Services Revolving Credit Facility repayment, which included borrowings of $465 million primarily used to fund an acquisition, offset by a repayment of $500 million drawn under the new Noble Midstream Services Term Loan Credit Facility. We also used $384 million of cash to redeem senior notes, for which payment of accrued interest of $11 million is reflected within operating activities.

In addition, during the first nine months of 2018, we used cash of $223 million pursuant to our stock repurchase program and paid $156 million of cash dividends to Noble Energy shareholders and $35 million of cash distributions to Noble Midstream Partners noncontrolling interest owners. We also received $348 million of contributions from noncontrolling interest owners. Other financing activities used net cash of $51 million.

In comparison, our primary financing activities during the first nine months of 2017 included $275 million, net, of 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, of proceeds from the issuance of Noble Midstream Partners common units and paid $141 million of cash dividends and $19 million of cash distributions. Other financing activities used net cash of $72 million.

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

Dividends On October 23, 2018, our Board of Directors declared a quarterly cash dividend of 11 cents per Noble Energy common share, which will be paid on November 19, 2018 to shareholders of record on November 5, 2018. 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.

Capital Expenditure Activities The following presents our capital expenditures (on an accrual basis) for the third quarter and first nine months of 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2018	2017	2018	2017
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition (1) (2)	$ 8	$ (10)	$ 21	$ 1,816
Proved Property Acquisition (1) (3)	—	(2)	—	839
Exploration and Development	676	585	2,090	1,783
Midstream(4)	69	96	685	342
Corporate and Other	11	11	38	24
Total	$ 764	$ 680	$ 2,834	$ 4,804
Investment in Equity Method Investee (5)	$ —	$ —	$ —	$ 68
Increase in Capital Lease Obligations	$ 9	$ —	$ 9	$ —

(1) Unproved and Proved property acquisition costs for the three months ended September 30, 2017 included purchase price adjustments related to the Clayton Williams Energy Acquisition.

(2) Unproved property acquisition costs for the first nine months of 2018 relate to leasing activity. Unproved property acquisition costs for the first nine months of 2017 included $1.6 billion related to the Clayton Williams Energy Acquisition and $246 million related to the Delaware Basin asset acquisition.

(3) Proved property acquisition costs for the first nine months of 2017 included $724 million of proved properties and $59 million of asset retirement obligations acquired in the Clayton Williams Energy Acquisition and $58 million related to the Delaware Basin asset acquisition.

(4) Midstream expenditures for first nine months of 2018 included $206 million related to the Saddle Butte acquisition. Midstream expenditures for the first nine months of 2017 included $68 million related to the Clayton Williams Energy Acquisition.

(5) 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.

Exploration and development costs for third quarter and first nine months of 2018 increased as compared with third quarter and first nine months of 2017 due to increased US onshore activity and Leviathan development activities. For the first nine months of 2018, exploration and development costs include approximately $1.6 billion for US onshore E&P operations and approximately $514 million for Leviathan. The increase in costs was partially offset by a decrease due to the 2017 Marcellus Shale divestiture. In addition, Midstream capital spending, exclusive of acquisitions, increased in first nine months of 2018 due to the construction of gathering systems in the DJ and Delaware Basins.

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 - E&P, 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, 2018, 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 liability position with a fair value of $394 million. Based on the September 30, 2018 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 increase the fair value of our net commodity derivative liability by approximately $236 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

Interest Rate Risk

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

At September 30, 2018, we had approximately $6.4 billion (excluding capital lease obligations) of long-term debt outstanding, net of unamortized discount and debt issuance costs. Of this amount, $5.8 billion was fixed-rate debt, net of unamortized discount and debt issuance costs, with a weighted average interest rate of 5.06%. 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, 2018, our cash and cash equivalents totaled $720 million, approximately 29% 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, Noble Midstream Services Term Loan Credit Facility and Leviathan 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, 2018, 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 or amounts, if any, outstanding under the above-named facilities would have a de minimis impact on our consolidated net income. See Item 1. Financial Statements – Note 5. Debt.

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, for example certain local working capital items, are denominated in a foreign currency and remeasured into US dollars. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative and tax liabilities.

Net transaction gains and losses were de minimis for the third quarter and first nine months of 2018.

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, information technology and security 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, 2017 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, 2017 is available on our website at www.nblenergy.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 13. 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, 2017.

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, 2017, other than the following:

Colorado Proposition #112, if approved by voters on November 6, 2018, could significantly limit, or in some cases prevent, the future development of crude oil and natural gas in areas where we currently conduct operations.

Current regulations in the state of Colorado require oil and gas development to maintain a 500-foot set-back from certain structures and a 1,000-foot set-back from certain high-occupancy buildings. However, on November 6, 2018, Colorado voters will decide whether to adopt Proposition #112, which, if passed, would increase the set-back zone for new "oil and gas development" to 2,500 feet. The term "oil and gas development" in Proposition #112 is defined to include oil and gas exploration, drilling, production and processing activities, as well as hydraulic fracturing, the reentry of an oil or gas well previously plugged or abandoned, flowlines and the treatment of waste associated with such exploration, drilling, production and processing activities. As proposed under Proposition #112, the set-back increase would be applicable to "occupied structures" and "vulnerable areas". "Vulnerable areas" is defined to include playgrounds, permanent sports fields, public parks and open spaces, public drinking water sources, reservoirs, lakes, rivers, perennial and intermittent streams, creeks, and any other area designated as such by the state or local government; however, the proposition provides no guidance on when or how such governments may exercise this authority. If adopted, Proposition #112 is expected to take effect upon official certification of election results, to be self-executing, and to apply to new oil and gas development that is permitted on or after the date of certification; it is not expected to apply to previously permitted wells, including drilled but uncompleted wells. The Colorado Oil and Gas Conservation Commission estimates that adoption of Proposition #112 would result in approximately 85% of Colorado's non-federal land surface becoming unavailable for new oil and gas development. In Weld County alone, 78% of surface land (85% of non-federal land) would appear to be off-limits to new oil and gas development.

The adoption of Proposition #112 could significantly limit, or in some cases prevent, the future development of crude oil and natural gas in areas where we currently conduct operations. Moreover, Proposition #112 could simultaneously curtail demand for our midstream services within the state. As such, our future drilling activities in Colorado could be significantly limited or hindered, and the amounts that we are ultimately able to produce from our undeveloped reserves in Colorado could be adversely affected.

In addition, if Proposition #112 is adopted, or other regulatory measures go into effect, we may incur additional costs to comply with any of its requirements or may experience delays and/or curtailment in the permitting or pursuit of our exploration, development, or production activities. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our cash flows, results of operations, financial condition, and liquidity. Adoption of Proposition #112 could result in a decrease in our proved undeveloped reserves and even a material impairment of our Colorado assets.

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 [2]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(millions)
7/1/2018 - 7/31/2018	70	$ 37.23	—	
8/1/2018 - 8/31/2018	1,366,585	29.72	1,366,533	
9/1/2018 - 9/30/2018	2,044,590	30.28	2,044,590	
Total	3,411,245	$ 30.05	3,411,123	$ 517

(1) Includes stock repurchases of 122 shares during the period relating 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.

(2) During third quarter 2018, we repurchased and retired 3,411,123 shares of common stock at an average purchase price of $30.07 per share pursuant to the $750 million share repurchase program, authorized by our Board of Directors, which expires December 31, 2020.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Exhibit*
2.1	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).
2.2	Agreement and Plan of Merger, dated as of May 10, 2015, by and among Noble Energy, Inc., Bluebonnet Merger Sub Inc. and Rosetta Resources Inc. (filed as Exhibit 2.1 of the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed on May 11, 2015 and incorporated herein by reference).
2.3	Exchange Agreement, executed October 29, 2016, by and between CNX Gas Company LLC and Noble Energy, Inc. (filed 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).
3.1	Restated Certificate of Incorporation of Noble Energy Inc., (filed as Exhibit 3.3 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. (as amended through January 30, 2018) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 30, 2018) filed on February 1, 2018 and incorporated herein by reference).
3.3	Certificate of Elimination of the Series A Junior Participating Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.4	Certificate of Elimination of the Series B Mandatorily Convertible Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
10.1	Noble Energy, Inc. Short-Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 and incorporated herein by reference).
12.1	Calculation of ratio of earnings to fixed charges, filed herewith.
31.1	Certification of the Company's Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	Certification of the Company's Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	Certification of the Company's Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), furnished herewith.
32.2	Certification of the Company's Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), furnished herewith.
101.INS	Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

101.DEF	XBRL Definition Linkbase Document

* 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 November 1, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Executive Vice President, Chief Financial Officer

EXHIBIT 12.1

Noble Energy, Inc.

Calculation of Ratio of Earnings to Fixed Charges

	Nine Months Ended September 30,	Year Ended December 31,				
	2018	2017	2016	2015	2014	2013
(millions, except ratio amounts)						
Income (Loss) From Continuing Operations Before Income Tax, Non-controlling Interests and Income From Equity Investees	$ 662	$ (2,436)	$ (1,887)	$ (2,309)	$ 1,540	$ 1,138
Add (Deduct)						
Fixed Charges	291	426	440	435	349	296
Capitalized Interest	(53)	(49)	(84)	(144)	(116)	(121)
Distributed Income From Equity Investees	136	139	83	77	226	204
Earnings (Loss) as Defined	$ 1,036	$ (1,920)	$ (1,448)	$ (1,941)	$ 1,999	$ 1,517
Net Interest Expense	216	354	328	263	210	158
Capitalized Interest	53	49	84	144	116	121
Interest Portion of Rental Expense	22	23	28	28	23	17
Fixed Charges as Defined	$ 291	$ 426	$ 440	$ 435	$ 349	$ 296
Ratio of Earnings to Fixed Charges	3.6	—	—	—	5.7	5.1
Amount by Which Earnings Were Insufficient to Cover Fixed Charges	$ —	$ 2,346	$ 1,888	$ 2,376	$ —	$ —

Exhibit 31.1

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: November 1, 2018

/s/ David L. Stover

David L. Stover
Chief Executive Officer

Exhibit 31.2

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: November 1, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer

Exhibit 32.1

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, 2018 (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: November 1, 2018

/s/ David L. Stover

David L. Stover
Chief Executive Officer

Exhibit 32.2

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, 2018 (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:	November 1, 2018	*/s/ Kenneth M. Fisher*
		Kenneth M. Fisher
		Chief Financial Officer