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

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

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	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 June 30, 2018, there were 483,118,790 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Oil, NGL and Gas Sales	$ 1,100	$ 1,017	$ 2,273	$ 2,011
Income from Equity Method Investees and Other	130	42	243	84
Total	1,230	1,059	2,516	2,095
Costs and Expenses				
Production Expense	292	283	613	586
Exploration Expense	29	30	64	72
Depreciation, Depletion and Amortization	465	503	933	1,031
Loss on Marcellus Shale Upstream Divestiture	—	2,322	—	2,322
Gain on Divestitures, Net	(78)	—	(666)	—
Asset Impairments	—	—	168	—
General and Administrative	105	103	209	202
Other Operating Expense, Net	74	118	144	147
Total	887	3,359	1,465	4,360
Operating Income (Loss)	343	(2,300)	1,051	(2,265)
Other (Income) Expense				
Loss (Gain) on Commodity Derivative Instruments	249	(57)	328	(167)
Interest, Net of Amount Capitalized	73	96	146	183
Other Non-Operating Expense (Income), Net	11	(5)	24	(6)
Total	333	34	498	10
Income (Loss) Before Income Taxes	10	(2,334)	553	(2,275)
Income Tax Expense (Benefit)	16	(836)	(15)	(824)
Net (Loss) Income and Comprehensive (Loss) Income Including Noncontrolling Interests	(6)	(1,498)	568	(1,451)
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	17	14	37	25
Net (Loss) Income and Comprehensive Income (Loss) Attributable to Noble Energy	$ (23)	$ (1,512)	$ 531	$ (1,476)
Net (Loss) Income Attributable to Noble Energy per Common Share				
Basic	$ (0.05)	$ (3.20)	$ 1.09	$ (3.27)
Diluted	$ (0.05)	$ (3.20)	$ 1.09	$ (3.27)
Weighted Average Number of Common Shares Outstanding				
Basic	484	472	485	452
Diluted	484	472	487	452

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

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

	June 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 621	$ 675
Accounts Receivable, Net	743	748
Other Current Assets	187	780
Total Current Assets	1,551	2,203
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	28,334	29,678
Property, Plant and Equipment, Other	896	879
Total Property, Plant and Equipment, Gross	29,230	30,557
Accumulated Depreciation, Depletion and Amortization	(11,313)	(13,055)
Total Property, Plant and Equipment, Net	17,917	17,502
Other Noncurrent Assets	984	461
Goodwill	1,402	1,310
Total Assets	$ 21,854	$ 21,476
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable – Trade	$ 1,308	$ 1,161
Other Current Liabilities	745	578
Total Current Liabilities	2,053	1,739
Long-Term Debt	6,555	6,746
Deferred Income Taxes	970	1,127
Other Noncurrent Liabilities	995	1,245
Total Liabilities	10,573	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; 526 Million and 529 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,329	8,438
Accumulated Other Comprehensive Loss	(28)	(30)
Treasury Stock, at Cost; 39 Million Shares	(731)	(725)
Retained Earnings	2,677	2,248
Noble Energy Share of Equity	10,252	9,936
Noncontrolling Interests	1,029	683
Total Equity	11,281	10,619
Total Liabilities and Equity	$ 21,854	$ 21,476

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

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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Cash Flows From Operating Activities		
Net Income (Loss) Including Noncontrolling Interests	$ 568	$ (1,451)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	933	1,031
Loss on Marcellus Shale Upstream Divestiture	—	2,322
Gain on Divestitures, Net	(666)	—
Asset Impairments	168	—
Deferred Income Tax Benefit	(164)	(873)
Loss (Gain) on Commodity Derivative Instruments	328	(167)
Net Cash (Paid) Received in Settlement of Commodity Derivative Instruments	(93)	14
Stock Based Compensation	35	67
Other Adjustments for Noncash Items Included in Income (Loss)	22	33
Changes in Operating Assets and Liabilities		
Decrease (Increase) in Accounts Receivable	76	(123)
(Decrease) Increase in Accounts Payable	(24)	120
Decrease in Current Income Taxes Payable	3	(42)
Other Current Assets and Liabilities, Net	(58)	(42)
Other Operating Assets and Liabilities, Net	(49)	(12)
Net Cash Provided by Operating Activities	1,079	877
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,782)	(1,215)
Proceeds from Sale of 7.5% Interest in Tamar Field	484	—
Proceeds from Sale of CONE Gathering LLC and CNX Midstream Partners Common Units	443	—
Proceeds from Gulf of Mexico Divestiture	383	—
Proceeds from Marcellus Shale Upstream Divestiture	—	1,028
Clayton Williams Energy Acquisition	—	(616)
Acquisitions, Net of Cash Acquired	(650)	(351)
Proceeds from Other Divestitures	72	101
Additions to Equity Method Investments	—	(68)
Other	—	—
Net Cash Used in Investing Activities	(1,050)	(1,121)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(102)	(92)
Purchase and Retirement of Common Stock	(130)	—
Proceeds from Noble Midstream Services Revolving Credit Facility	610	195
Repayment of Noble Midstream Services Revolving Credit Facility	(165)	(5)
Contributions from Noncontrolling Interest Owners	331	—
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	138
Proceeds from Revolving Credit Facility	905	1,310
Repayment of Revolving Credit Facility	(1,135)	(1,310)
Repayment of Clayton Williams Energy Long-term Debt	—	(595)
Repayment of Senior Notes	(384)	—
Other	(51)	(67)
Net Cash Used in Financing Activities	(121)	(426)
Decrease in Cash, Cash Equivalents, and Restricted Cash	(92)	(670)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	713	1,210
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 621	$ 540

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	—	—	—	—	531	37	568
Stock-based Compensation	—	46	—	—	—	—	46
Dividends (21 cents per share)	—	—	—	—	(102)	—	(102)
Purchase and Retirement of Common Stock	—	(130)	—	—	—	—	(130)
Clayton Williams Energy Acquisition	—	(25)	—	—	—	—	(25)
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(22)	(22)
Contributions from Noncontrolling Interest Owners	—	—	—	—	—	331	331
Other	—	—	2	(6)	—	—	(4)
June 30, 2018	$ 5	$ 8,329	$ (28)	$ (731)	$ 2,677	$ 1,029	$ 11,281
December 31, 2016	$ 5	$ 6,450	$ (31)	$ (692)	$ 3,556	$ 312	$ 9,600
Net (Loss) Income	—	—	—	—	(1,476)	25	(1,451)
Clayton Williams Energy Acquisition	—	1,876	—	(25)	—	—	1,851
Stock-based Compensation	—	65	—	—	—	—	65
Dividends (20 cents per share)	—	—	—	—	(92)	—	(92)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	138	138
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(12)	(12)
Other	—	8	1	(10)	—	—	(1)
June 30, 2017	$ 5	$ 8,399	$ (30)	$ (727)	$ 1,988	$ 463	$ 10,098

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

Note 1. Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our 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 owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US GAAP for complete financial statements. The accompanying consolidated financial statements at June 30, 2018 and December 31, 2017 and for the three and six months ended June 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. For the periods presented, activity within other comprehensive income or loss was de minimis; therefore, net income is materially consistent with comprehensive income or loss.

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

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 asset, which is currently over periods of seven to 13 years. As of June 30, 2018, the gross book value of the intangible asset was $340 million. Amortization expense of $9 million and $14 million for the three and six months ended June 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 second quarter and the first six months of 2018, we repurchased and retired 1.8 million shares and 4.0 million shares of common stock at an average purchase price of $35.15 per share and $32.41 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 de minimis increases of $2 million and $7 million to both revenues and expenses for second quarter and the first six 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.

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 the 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 sale 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 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, 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 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)	July - Dec 2018	2019	2020	Total
Natural Gas Revenues [1]	$ 107	$ 137	$ 169	$ 413

[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

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 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 assets and liabilities on the balance sheet for the rights and obligations created by leases with terms of more than 12 months. 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 January 2018, the FASB issued Accounting Standards Update No. 2018-01 (ASU 2018-01): *Land Easement Practical Expedient for Transition to Topic 842*, to provide an optional practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under Topic 840. In July 2018, the FASB issued Accounting Standards Update No. 2018-10 (ASU 2018-10): *Codification Improvements to Topic 842, Leases*, to clarify application of certain aspects of the standard and to remove inconsistencies within the guidance. Furthermore, in July 2018, the FASB issued Accounting Standards Update No. 2018-11 (ASU 2018-11): *Leases (Topic 842): Targeted Improvements*, which provides for another transition method, in addition to the existing 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 (i.e. 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, storage facilities, field services and well equipment, pipeline capacity, office space and other assets. We will adopt the new standard on the effective date of January 1, 2019. 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 in assets and liabilities as well as additional disclosures. We do not expect a material impact on our consolidated statement of operations. We have developed and are executing a project plan, which includes contract review and assessment, as well as evaluation of our systems, processes and internal controls. In addition, we plan to implement new lease accounting software.

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. ASU 2018-02 will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. As of June 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 this standard.

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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2018	2017	2018	2017
Income From Equity Method Investees and Other				
Income from Equity Method Investees	$ 49	$ 38	$ 96	$ 80
Sales of Purchased Oil and Gas (1)	66	—	119	—
Midstream Services Revenues – Third Party	15	4	28	4
Total	$ 130	$ 42	$ 243	$ 84
Production Expense				
Lease Operating Expense	$ 132	$ 124	$ 287	$ 263
Production and Ad Valorem Taxes	50	32	104	73
Gathering, Transportation and Processing Expense	100	121	195	240
Other Royalty Expense	10	6	27	10
Total	$ 292	$ 283	$ 613	$ 586
Exploration Expense				
Leasehold Impairment and Amortization	$ —	$ —	$ —	$ 18
Seismic, Geological and Geophysical	2	8	13	13
Staff Expense	13	16	27	29
Other	14	6	24	12
Total	$ 29	$ 30	$ 64	$ 72
Other Operating Expense, Net				
Marketing Expense (2)	$ 7	$ 14	$ 12	$ 33
Purchased Oil and Gas (1)	71	—	128	—
Clayton Williams Energy Acquisition Expenses	—	90	—	94
Other, Net	(4)	14	4	20
Total	$ 74	$ 118	$ 144	$ 147
Other Non-Operating Expense (Income), Net				
Loss on Investment in Shares of Tamar Petroleum Ltd., Net (3)	$ 11	$ —	$ 26	$ —
Other	—	(5)	(2)	(6)
Total	$ 11	$ (5)	$ 24	$ (6)

(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 have 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. The cost to purchase natural gas includes transportation expense incurred of $6 million and $11 million for second quarter and the first six months of 2018, respectively. See Note 11. Segment Information and Note 12. Commitments and Contingencies.

(2) Expense relates to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.

(3) Amounts for second quarter and the first six months of 2018 include losses of $11 million and $40 million, respectively, related to the change in fair value. The loss for the six months ended June 30, 2018 is partially offset by dividend income of $14 million. There was no dividend income for second quarter 2018.

Balance Sheet Information Other balance sheet information is as follows:

(millions)	June 30, 2018	December 31, 2017
Accounts Receivable, Net		
Commodity Sales	$ 460	$ 455
Joint Interest Billings	210	207
Other	89	103
Allowance for Doubtful Accounts	(16)	(17)
Total	$ 743	$ 748
Other Current Assets		
Inventories, Materials and Supplies	$ 46	$ 66
Inventories, Crude Oil	27	16
Commodity Derivative Assets	29	2
Assets Held for Sale [1]	40	629
Restricted Cash [2]	—	38
Prepaid Expenses and Other Current Assets	45	29
Total	$ 187	$ 780
Other Noncurrent Assets		
Equity Method Investments [3]	$ 357	$ 305
Customer-Related Intangible Assets [4]	326	—
Investment in Shares of Tamar Petroleum Ltd. [5]	150	—
Mutual Fund Investments	57	57
Net Deferred Income Tax Asset	25	25
Other Assets, Noncurrent	69	74
Total	$ 984	$ 461
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 111	$ 84
Commodity Derivative Liabilities	250	58
Income Taxes Payable	5	18
Asset Retirement Obligations	92	51
Interest Payable	64	67
Current Portion of Capital Lease Obligations	47	61
Liabilities Associated with Assets Held for Sale [1]	—	55
Compensation and Benefits Payable	66	98
Other Liabilities, Current	110	86
Total	$ 745	$ 578
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$ 180	$ 197
Asset Retirement Obligations	543	824
Marcellus Shale Firm Transportation Commitment [6]	71	76
Production and Ad Valorem Taxes	39	69
Commodity Derivative Liabilities	85	15
Other Liabilities, Noncurrent	77	64
Total	$ 995	$ 1,245

(1) Assets held for sale at June 30, 2018 include assets in the Greeley Crescent area of the DJ Basin. 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 interest 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 December 31, 2017 represents amount held in escrow pending closing of the Saddle Butte acquisition. See Note 3. Acquisitions and Divestitures.

(3) Includes $49 million for our investment in shares of CNX Midstream Partners LP. 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.

(4) Amount relates to intangible assets acquired in the Saddle Butte acquisition and is net of $14 million of accumulated amortization. See Note 3. Acquisitions and Divestitures.

(5) 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.

(6) Amounts relate to the long-term portion of retained firm transportation agreements. At June 30, 2018 and December 31, 2017, we recorded $12 million and $14 million, respectively, associated with the current portion of the Marcellus Shale firm transportation commitment. See Note 12. Commitments and Contingencies.

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

	Six Months Ended June 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	$ 621	$ 540
Restricted Cash at End of Period	—	—
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 621	$ 540

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, we received net proceeds of $383 million and recorded an additional loss of $19 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 June 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.

Our shares of Tamar Petroleum are currently 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 currently being accounted for at fair value. See Note 6. Fair Value Measurements and Disclosures.

Total consideration received 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.

The sale is in accordance with the terms of the Israel Natural Gas Framework (Framework) that requires us to reduce our ownership interest in the Tamar field from 32.5% to 25% by year-end 2021. We expect to sell the Tamar Petroleum shares before year-end 2021. Proved reserves related to the 7.5% interest totaled approximately 84 MMBoe as of December 31, 2017.

Divestiture of Southwest Royalties In January 2018, we closed the sale of our interest 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 continued to hold 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 underwriting fees, and recognized a gain of $109 million. As of June 30, 2018, we continue to hold 14.2 million common units, representing a 22.3% limited partner interest, in CNX Midstream Partners and account for the investment under equity method accounting.

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 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 $111 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 six months of 2018, we also closed the sale of certain other smaller US onshore properties and received total cash consideration of $12 million, recording a gain of $4 million.

2017 Asset Transactions

Delaware Basin Acquisition During the first six 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 ne t 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 represent 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, represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved, possible and probable reserves; (ii) production rates and related development timing; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by management at the time of the valuation and were the most sensitive.

Based upon the final purchase price allocation, we recognized $1.3 billion of goodwill, all of which is 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 Acquisitio n taken place on January 1, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except per share amounts)	2018 [(1)]	2017	2018 [(1)]	2017
Revenues	$ 1,230	$ 1,070	$ 2,516	$ 2,141
Net (Loss) Income and Comprehensive (Loss) Income Attributable to Noble Energy	(23)	(1,354)	531	(1,324)
Net (Loss) Income Attributable to Noble Energy per Common Share				
Basic	$ (0.05)	$ (2.77)	$ 1.09	$ (2.71)
Diluted	$ (0.05)	$ (2.77)	$ 1.09	$ (2.71)

(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. Commitments and Contingencies.

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 June 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	6,000	—	—	50.00	60.00	72.75
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 June 30, 2018, the following natural gas derivative contracts were outstanding:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Three-Way Collars	NYMEX HH	120,000	$ —	$ 2.50	$ 2.88	$ 3.65

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			
	June 30, 2018		December 31, 2017		June 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	$ 29	Current Assets	$ 2	Current Liabilities	$ 250	Current Liabilities	$ 58
	Noncurrent Assets	—	Noncurrent Assets	—	Noncurrent Liabilities	85	Noncurrent Liabilities	15
Total		$ 29		$ 2		$ 335		$ 73

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2018	2017	2018	2017
Cash Paid (Received) in Settlement of Commodity Derivative Instruments				
Crude Oil	$ 66	$ (11)	$ 96	$ (16)
Natural Gas	(1)	—	(3)	2
Total Cash Paid (Received) in Settlement of Commodity Derivative Instruments	65	(11)	93	(14)
Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	181	(28)	231	(91)
Natural Gas	3	(18)	4	(62)
Total Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments	184	(46)	235	(153)
Loss (Gain) on Commodity Derivative Instruments				
Crude Oil	247	(39)	327	(107)
Natural Gas	2	(18)	1	(60)
Total Loss (Gain) on Commodity Derivative Instruments	$ 249	$ (57)	$ 328	$ (167)

Note 5. Debt

Debt consists of the following:

	June 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	530	3.25%	85	2.75%
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	241	—%	273	—%
Total	6,663		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	6,602		6,807	
Less Amounts Due Within One Year				
Capital Lease Obligations	(47)		(61)	
Long-Term Debt Due After One Year	$ 6,555		$ 6,746	

(1) In second quarter 2018, we redeemed all of the Senior Notes due May 1, 2021, writing off 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 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 June 30, 2018, no borrowings were outstanding under the Revolving Credit Facility.

Noble Midstream Services Revolving Credit Facility Noble Midstream Services, LLC, 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 facility 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.

As of June 30, 2018, $530 million was outstanding under the Noble Midstream Services Revolving Credit Facility. The increase from December 31, 2017 was primarily used to fund the Saddle Butte acquisition, as well as construction activities. See Note 3. Acquisitions and Divestitures.

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 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 June 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, is $1.0 billion of senior notes which mature in 2021. The Revolving Credit Facility and Noble Midstream Services Revolving Credit Facility both mature in March 2023. No other balances are due within the next five years.

Subsequent Event - Noble Midstream Services Term Credit Agreement On July 31, 2018, Noble Midstream Services, LLC entered into a three year senior unsecured term loan credit facility (Noble Midstream Services Term Credit Agreement) that permits aggregate borrowings of up to $500 million. Proceeds from the Noble Midstream Services Term Credit Agreement will be used to repay a portion of the outstanding borrowings under the Noble Midstream Services Revolving Credit Facility, pay fees and expenses in connection with the Noble Midstream Services Term Credit Agreement transactions and for working capital, capital expenditures, acquisitions and other purposes as necessary of Noble Midstream Partners and its subsidiaries.

Borrowings under the Noble Midstream Services Term Credit Agreement will 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.

The Noble Midstream Services Term Credit Agreement 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 Credit Agreement, the lenders may declare all amounts outstanding under the Noble Midstream Services Term Credit Agreement to be immediately due and payable and exercise other remedies as provided by applicable law.

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. The fair value of these shares is determined at the end of each quarter based on the trading price of Tamar Petroleum shares on the Tel Aviv Stock Exchange and is reduced by a 15% discount. The discount rate is based on analysis of historical discounts realized in private placements of public common stock, which we believe represents a reasonable estimate of the impact of the temporary lock-up provisions applicable to the shares we own. 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
June 30, 2018					
Financial Assets:					
Mutual Fund Investments	$ 57	$ —	$ —	$ —	$ 57
Commodity Derivative Instruments	—	72	—	(43)	29
Investment in Tamar Petroleum Ltd. (38,495,575 Shares) [5]	—	150	—	—	150
Financial Liabilities:					
Commodity Derivative Instruments	—	(378)	—	43	(335)
Portion of Deferred Compensation Liability Measured at Fair Value	(73)	—	—	—	(73)
Stock Based Compensation Liability Measured at Fair Value	(12)	—	—	—	(12)
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.
(5) As of June 30, 2018, the closing price on the TASE of publicly traded and unrestricted shares of Tamar Petroleum Ltd. was $4.60 per share.

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 quarter 2018 and the first six 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, is accounted for using the equity method. The fair value of the investment is based on the published market price of the common units for the date indicated below.

	June 30, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investment in CNX Midstream Partners (14,217,198 Common Units and 21,692,198 Common Units, respectively) (1)	$ 49	$ 276	$ 70	$ 364

(1) During second quarter 2018, we sold 7.5 million common units, reducing our ownership in CNX Midstream Partners. See Note 3. Acquisitions and Divestitures.

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 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:

	June 30, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt (1)	$ 6,422	$ 6,591	$ 6,586	$ 7,142

(1) 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)	Six Months Ended June 30, 2018
Capitalized Exploratory Well Costs, Beginning of Period	$ 520
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	4
Divestitures (1)	(167)
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	$ 356

(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)	June 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	348	510
Balance at End of Period	$ 356	$ 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 June 30, 2018, we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of $2.6 billion, including $1.6 billion related to Delaware Basin assets acquired in the Clayton Williams Energy Acquisition in 2017, and $859 million and $129 million attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Merger in 2015. Undeveloped leasehold costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and are subject to impairment testing.

The remaining balance of undeveloped leasehold costs as of June 30, 2018 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 half of 2018, we transferred $247 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 was removed from undeveloped leasehold costs due to divestiture of the associated assets in second quarter 2018. 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:

	Six Months Ended June 30,	
(millions)	2018	2017
Asset Retirement Obligations, Beginning Balance	$ 875	$ 935
Liabilities Incurred	14	82
Liabilities Settled	(261)	(32)
Revisions of Estimates	(10)	(15)
Accretion Expense (1)	17	23
Asset Retirement Obligations, Ending Balance	$ 635	$ 993

(1) Accretion expense is included in depreciation, depletion and amortization (DD&A) expense in the consolidated statements of operations.

For the Six Months Ended June 30, 2018 Liabilities settled include $216 million of liabilities assumed by the purchaser of the Gulf of Mexico properties and $44 million related to abandonment of US onshore properties, primarily in the DJ Basin. Revisions of estimates primarily relate to decreases in cost and timing estimates of $11 million associated with the North Sea abandonment project and $6 million for Eastern Mediterranean, partially offset by an increase of $7 million for US onshore.

For the Six Months Ended June 30, 2017 Liabilities incurred include $59 million related to the Clayton Williams Energy Acquisition and $23 million primarily for other US onshore wells and facilities placed into service. Liabilities settled primarily related to US onshore property abandonments, as well as $12 million related to properties sold in the Marcellus Shale upstream divestiture. Revisions of estimates related to decreases in cost and timing estimates of $30 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 (benefit) expense consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except percentages)	2018	2017	2018	2017
Current	$ 23	$ 37	$ 149	$ 49
Deferred	(7)	(873)	(164)	(873)
Total Income Tax Expense (Benefit)	$ 16	$ (836)	$ (15)	$ (824)
Effective Tax Rate	160.0%	35.8%	(2.7)%	36.2%

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.

During second quarter 2018, we made no changes to the provisional amounts recognized in 2017.

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, based on current legal interpretations. This amount may be adjusted further in future periods, as an adjustment to income tax expense or benefit, in the period in which the final amounts are determined.

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 result in significant interim ETR fluctuations. Our ETR for the six months ended June 30, 2018 varied as compared with the six months ended June 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 six months ended June 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 June 30,		Six Months Ended June 30,	
(millions, except per share amounts)	2018	2017	2018	2017
Net (Loss) Income and Comprehensive (Loss) Income Attributable to Noble Energy	$ (23)	$ (1,512)	$ 531	$ (1,476)
Weighted Average Number of Shares Outstanding, Basic	484	472	485	452
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	—	—	2	—
Weighted Average Number of Shares Outstanding, Diluted	484	472	487	452
(Loss) Income Per Share, Basic	$ (0.05)	$ (3.20)	$ 1.09	$ (3.27)
(Loss) Income Per Share, Diluted	(0.05)	(3.20)	1.09	(3.27)
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	14	16	14	15

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 (Falkland Islands, 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 owns, acquires, operates, and develops domestic midstream infrastructure assets, 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 June 30, 2018								
Crude Oil Sales	$ 749	$ 635	$ 2	$ 112	$ —	$ —	$ —	$ —
NGL Sales	137	137	—	—	—	—	—	—
Natural Gas Sales	214	98	111	5	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	1,100	870	113	117	—	—	—	—
Income from Equity Method Investees and Other	64	—	—	36	—	28	—	—
Sales of Purchased Oil and Gas	66	24	—	—	—	42	—	—
Intersegment Revenues	—	—	—	—	—	85	(85)	—
Total Revenues	1,230	894	113	153	—	155	(85)	—
Lease Operating Expense	132	114	5	19	—	—	(6)	—
Production and Ad Valorem Taxes	50	48	—	—	—	2	—	—
Gathering, Transportation and Processing Expense	100	133	—	—	—	22	(55)	—
Other Royalty Expense	10	10	—	—	—	—	—	—
Total Production Expense	292	305	5	19	—	24	(61)	—
DD&A	465	394	15	26	—	22	(4)	12
Loss (Gain) on Divestitures	(78)	21	10	—	—	(109)	—	—

Purchased Oil and Gas	71	31	—	—	—	40	—	—
Loss on Commodity Derivative Instruments	249	196	—	53	—	—	—	—
(Loss) Income Before Income Taxes	10	(90)	62	48	(13)	175	(18)	(154)
Three Months Ended June 30, 2017								
Crude Oil Sales	$ 557	$ 458	$ 1	$ 98	$ —	$ —	$ —	$ —
NGL Sales	108	108	—	—	—	—	—	—
Natural Gas Sales	352	214	132	6	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	1,017	780	133	104	—	—	—	—
Income from Equity Method Investees and Other	42	—	—	25	—	17	—	—
Intersegment Revenues	—	—	—	—	—	69	(69)	—
Total Revenues	1,059	780	133	129	—	86	(69)	—
Lease Operating Expense	124	105	6	18	—	—	(5)	—
Production and Ad Valorem Taxes	32	32	—	—	—	—	—	—
Gathering, Transportation and Processing Expense	121	142	—	—	—	17	(38)	—
Other Royalty Expense	6	6	—	—	—	—	—	—
Total Production Expense	283	285	6	18	—	17	(43)	—
DD&A	503	427	19	39	1	5	—	12
Loss on Marcellus Shale Upstream Divestiture	2,322	2,322	—	—	—	—	—	—
Loss on Commodity Derivative Instruments	(57)	(51)	—	(6)	—	—	—	—
(Loss) Income Before Income Taxes	(2,334)	(2,319)	106	72	(4)	58	(13)	(234)
Six Months Ended June 30, 2018								
Crude Oil Sales	$ 1,522	$ 1,317	$ 4	$ 201	$ —	$ —	$ —	$ —
NGL Sales	283	283	—	—	—	—	—	—
Natural Gas Sales	468	218	240	10	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	2,273	1,818	244	211	—	—	—	—
Income from Equity Method Investees and Other	124	—	—	71	—	53	—	—
Sales of Purchased Oil and Gas	119	55	—	—	—	64	—	—
Intersegment Revenues	—	—	—	—	—	166	(166)	—
Total Revenues	2,516	1,873	244	282	—	283	(166)	—
Lease Operating Expense	287	240	12	41	—	—	(6)	—
Production and Ad Valorem Taxes	104	101	—	—	—	3	—	—
Gathering, Transportation and Processing Expense	195	260	—	—	—	43	(108)	—
Other Royalty Expense	27	27	—	—	—	—	—	—
Total Production Expense	613	628	12	41	—	46	(114)	—
DD&A	933	800	28	52	—	38	(8)	23
Gain on Divestitures	(666)	15	(376)	—	—	(305)	—	—

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

Asset Impairments	168	168	—	—	—	—	—	—
Purchased Oil and Gas	128	67	—	—	—	61	—	—
Loss on Commodity Derivative Instruments	328	260	—	68	—	—	—	—
Income (Loss) Before Income Taxes	553	(127)	535	112	(27)	428	(40)	(328)
Six Months Ended June 30, 2017								
Crude Oil Sales	$ 1,084	$ 897	$ 2	$ 185	$ —	$ —	$ —	$ —
NGL Sales	213	213	—	—	—	—	—	—
Natural Gas Sales	714	440	263	11	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	2,011	1,550	265	196	—	—	—	—
Income from Equity Method Investees and Other	84	—	—	52	—	32	—	—
Intersegment Revenues	—	—	—	—	—	127	(127)	—
Total Revenues	2,095	1,550	265	248	—	159	(127)	—
Lease Operating Expense	263	211	14	40	—	—	(2)	—
Production and Ad Valorem Taxes	73	72	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	240	280	—	—	—	32	(72)	—
Other Royalty Expense	10	10	—	—	—	—	—	—
Total Production Expense	586	573	14	40	—	33	(74)	—
DD&A	1,031	886	37	74	2	10	—	22
Loss on Marcellus Shale Upstream Divestiture	2,322	2,322	—	—	—	—	—	—
Gain on Commodity Derivative Instruments	(167)	(154)	—	(13)	—	—	—	—
Income (Loss) Before Income Taxes	(2,275)	(2,251)	207	138	(11)	107	(35)	(430)
June 30, 2018								
Goodwill [2]	$ 1,402	$ 1,291	$ —	$ —	$ —	$ 111	$ —	$ —
Total Assets	21,854	15,138	2,996	1,275	62	2,280	(140)	243
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 Saddle Butte acquisition.

Note 12. Commitments and Contingencies

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

Marcellus Shale Firm Transportation Contracts In connection with the 2017 Marcellus Shale upstream divestiture, we retained certain firm transportation obligations to flow Marcellus Shale natural gas production to various markets inside and outside of the Marcellus Basin. Our financial commitment for these agreements, which have remaining terms of approximately four to 15 years, is approximately $1.4 billion, undiscounted. The agreements for firm transportation primarily relate to services on certain pipelines which were placed into service in late 2017 and early 2018 or for services on new pipeline projects to be constructed by, and connecting to, existing and new interstate pipeline systems, with estimated in-service dates in late 2018.

We are currently engaged in actions to commercialize these commitments which provide for the transportation of 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 continue to expect these actions, some of which 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, at fair value, for the net amount of the estimated remaining commitments under these contracts. As of June 30, 2018, our exit cost accrual, relating to certain transportation arrangements, totals $83 million, discounted. For the first six months of 2018, we incurred expense of $3 million related to unutilized transportation related to these contracts.

Colorado Air Matter In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream crude oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the 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, and mitigation expenditures that resulted from this settlement did not have, and based on currently available information will not have, a material adverse effect on our financial position, results of operations or cash flows.

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

Colorado Oil and Gas Conservation Commission Administrative Order on Consent In November 2017, we received a proposed Administrative Order on Consent (AOC) from the Colorado Oil and Gas Conservation Commission (COGCC) to resolve allegations of noncompliance associated with site preparation and stabilization at an oil and gas location in Weld County, Colorado. The AOC, which provides for an opportunity to further discuss the offer of settlement, has not yet been executed. 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 Mechanical Integrity Testing Matter In July 2018, we received Notices of Alleged Violation (NOAVs) from the COGCC for alleged noncompliance of State mechanical integrity testing rules at eight shut-in wells in Weld County, Colorado. The NOAVs order us to repair or plug and abandon each of the eight wells (or provide proof that such work has been completed) and to submit to COGCC certain environmental data. We have met with COGCC enforcement leadership to discuss this matter and are working to timely complete the required corrective actions and submit the data requested in the NOAVs. 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.

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

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

- Executive Overview;
- Operating Outlook;
- Results of Operations – E&P;
- Results of Operations – Midstream;
- Results of Operations – Corporate; and
- Liquidity and Capital Resources.

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

EXECUTIVE OVERVIEW

The following discussion highlights significant operating and financial results for second 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."

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 second quarter 2018, we exited the Gulf of Mexico and continued to progress our US onshore drilling and completions activities and advanced our

Eastern Mediterranean and West Africa regional natural gas developments. Financially, we strengthened our balance sheet through reduction of debt.

Second quarter 2018 achievements include the following:

Sales Volumes We delivered quarterly sales volumes of 346 MBoe/d with approximately 56% 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.

Gulf of Mexico Asset Sale In second quarter 2018, we completed the sale of our Gulf of Mexico assets, including our interests in six producing fields and all undeveloped leases. We received cash consideration of $383 million, net of customary price adjustments. We recognized impairment expense of $168 million in first quarter 2018 and an additional loss of $19 million in second quarter 2018. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Agreement to Progress Alen Natural Gas Development In May 2018, we announced the execution of a Heads of Agreement establishing the framework for development of natural gas from the Alen field, resulting in access to global liquefied natural gas (LNG) markets. Sanction of the project is contingent upon final commercial agreements being executed. See Exploration and Production (E&P) – Development Projects.

Strategic EPIC Pipeline Agreement During second quarter 2018, we finalized a strategic agreement with EPIC Pipeline, LP (EPIC) to transport crude oil from our Delaware Basin acreage position to Corpus Christi, Texas. We have secured firm capacity for 100 MBbl/d, gross, of crude oil for a 10-year period beginning at pipeline start-up. In addition, we secured options for ownership interests in EPIC's crude oil and NGL pipelines. See Exploration and Production (E&P) – Development Projects.

Delaware Basin Firm Crude Oil Sales Agreement In June 2018, we supplemented our Delaware Basin takeaway position through the execution of a five-year agreement for firm gross sales of at least 10 MBbl/d of crude oil beginning in July 2018, increasing to 20 MBbl/d beginning in October 2018 and for the remainder of the agreement. See Exploration and Production (E&P) – Development Projects.

Hedging Activities We entered into additional strategic crude oil basis swap contracts for 2018-2020 in order to establish a fixed amount for the differential between pricing in Midland, Texas, and Cushing, Oklahoma, thus mitigating the price risk associated with our Delaware Basin production. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

CNX Midstream Partners Unit Sale During second quarter 2018, we sold 7.5 million CNX Midstream Partners common units, or approximately one-third of our investment, receiving net proceeds of approximately $135 million, net of underwriting fees. We continue to hold 14.2 million common units. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Senior Note Redemption To further strengthen our balance sheet and reduce nearer-term maturities, we redeemed $379 million of Senior Notes due May 1, 2021, which had been assumed in the 2015 Rosetta Merger, in May 2018 for $395 million and recognized a gain of $5 million. See Item 1. Financial Statements – Note 5. Debt.

Share Repurchases In accordance with the $750 million share repurchase program authorized by our Board of Directors earlier this year, we repurchased and retired 1.8 million shares of common stock at an average purchase price of $35.15 per share during second 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 continuously evaluate commodity prices, along with well productivity and efficiency gains, as we optimize our activity levels in alignment with commodity price conditions. To this end, our 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 begin to rise, we could experience material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and, in response, we may consider reductions in our capital program or dividends, asset sales or operating cost structure. Our production and our stock price could decline as a result of these potential developments.

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, and resulted in de minimis increases of $2 million and $7 million to both revenues and expenses for the second quarter and the first six months of 2018, respectively. ASC 606 adoption 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 Production Our expected crude oil, natural gas and NGL sales for the remainder of 2018 may be impacted by several factors including:

- commodity prices which, if subject to a significant decline, could result in certain existing production becoming uneconomic;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, will impact near-term production volumes;
- increased industry drilling activity in the basins in which we operate, which may cause US onshore cost inflation pressure and result in certain current production becoming less profitable or uneconomic;
- Israeli industrial and residential demand for electricity, which is largely impacted by weather conditions and conversion of the Israeli electricity portfolio from coal to natural gas;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa;
- natural field decline in the US onshore and offshore Equatorial Guinea;
- additional purchases of producing properties or divestments of operating assets;

- potential weather-related volume curtailments (e.g., due to winter storms and flooding) impacting US onshore operations;
- availability or reliability of supplier materials and services, including access to support equipment and/or facilities which may cause delays in operations;
- availability of, or curtailments imposed by, third party processing facilities, which could result in capacity constraints, and interruptions in midstream processing, which may cause production and sales volumes impacts;
- occurrence of pipeline disruptions, which may cause delays, restrictions or interruptions in production and/or midstream processing;
- access to transportation and takeaway pipelines for increasing US onshore production volumes, such as in the Delaware Basin, which may cause infield bottlenecks and/or widening of location-basis differentials;
- malfunctions and/or mechanical failures at terminals or other US onshore delivery points;
- impact of enhanced completion efforts for US onshore assets;
- potential growth from participation in future, or decline from existing, non-operated wells;
- abandonment of low-margin US onshore wells;
- shut-in of US producing properties if storage capacity becomes unavailable; and
- potential drilling and/or completion permit delays due to future regulatory changes.

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. We have revised our capital program to accommodate an investment level of approximately $3 billion, reflecting increased onshore facility spend from the first half of 2018 and inflation in the 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 and the Eastern Mediterranean. In addition, given industry constraints in the Permian Basin, we plan to reallocate some near-term investment to our other US onshore basins. 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.

Regulatory Update During the first six 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 Argentina, Brazil, and South Korea (Australia has been exempted from the imposition of tariffs and implementation of quotas). Key US trading partners have threatened to retaliate, or already have retaliated, against imports of US-origin goods and have initiated litigation at the World Trade Organization. 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 LNG export projects resulting in negative impacts on natural gas production.

In addition, countries subject to the tariffs have threatened to retaliate with tariffs on American products, potentially 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 second quarter 2018 were focused primarily in the Wells Ranch and East Pony integrated development plan (IDP) areas. During the quarter, we operated one to two drilling rigs, completed 31 wells and commenced production on 16 wells. Average sales volumes during second quarter 2018 were 121 MBoe/d, including 10 MBoe/d due to ASC 606 adoption. We have expanded drilling and completion activities into the Mustang IDP area, where we have a large contiguous acreage position, and added a drilling rig in this IDP during second quarter 2018. 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.

Delaware Basin (US Onshore) During second quarter 2018, we operated an average of six drilling rigs, completed 22 wells and commenced production on 23 wells, with the majority of our activity focused on long laterals and multi-well pads targeting multiple zones within the basin. We averaged 47 MBoe/d of sales volumes during second quarter 2018, with approximately 70% of our production mix attributable to crude oil. During second quarter 2018, we commenced operations at two additional central gathering facilities (CGFs).

Also during second quarter 2018, we secured firm capacity with EPIC for transport of 100 MBbl/d, gross, of crude oil from the Delaware Basin to Corpus Christi, Texas, for a 10-year period beginning at pipeline start-up. We have dedicated substantially all our Delaware Basin acreage position in Reeves County, Texas to the EPIC crude oil pipeline, which the operator anticipates will commence operations in the fourth quarter of 2019. This strategic agreement is expected to provide long-term flow assurance for our rapidly growing Delaware Basin crude oil volumes. With this agreement, we have further diversified our US onshore marketing outlets with access to the Texas Gulf Coast and global markets, at an attractive pipeline transport cost.

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. Both options expire in first quarter 2019.

In June 2018, we supplemented our Delaware Basin takeaway position with an additional firm sales agreement, which will result 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 beginning in July 2018, increasing to 20 MBbl/d beginning in October 2018 and for the remainder of the agreement. Crude oil sold under the agreement will initially utilize the buyer's existing firm transport capacity to Corpus Christi. Shortly following commencement of full service of the EPIC crude oil pipeline, 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 second quarter 2018, we operated an average of one drilling rig, completed four wells and commenced production on nine wells, primarily focused within the Upper and Lower Eagle Ford formation zones. In addition, we commenced construction of a central gathering and production facility in the northern area of Gates Ranch. This facility will provide separation and compression capabilities for our upcoming multi-well completion program expected to begin later in 2018. We continue to execute our development plan and averaged sales volumes of 76 MBoe/d during second quarter 2018.

Tamar Natural Gas Project (Eastern Mediterranean) In second quarter 2018, offshore Israel sales volumes averaged 227 MMcfe/d, net, and on a gross basis, sales volumes reached a cumulative milestone delivering 1.6 Tcf of natural gas to-date. Second quarter gross sales volumes established a quarterly production record of more than 1 Bcf/d, driven by continued coal displacement in power generation and warm seasonal weather.

Leviathan Natural Gas Project (Eastern Mediterranean) 2018 represents the peak year for capital investments for the initial phase of Leviathan development, offshore Israel. The project is now nearly 60% complete and remains on budget and on schedule. We have commenced construction of the onshore pipeline, completed drilling of Leviathan 3 and 7 wells, and began completion operations at the Leviathan 4 well. First natural gas sales are anticipated by the end of 2019.

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 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.

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 recorded as dry hole expense.

Additionally, we may not be able to conduct exploration activities prior to lease expirations. As a result, in a future period, dry hole cost and/or leasehold abandonment expense could be significant. See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Results of Operations

Highlights for our E&P business were as follows:

Second Quarter 2018 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 346 MBoe/d, net;
- record average daily sales volumes for US onshore crude oil of 105 MBbl/d, net;
- record average daily sales volumes of over 1 Bcf/d, gross, in Israel, primarily from the Tamar field;
- closed the Gulf of Mexico asset divestiture; and
- executed Heads of Agreement regarding framework for development of natural gas from the Alen field, offshore Equatorial Guinea.

Second Quarter 2018 E&P Financial Results Included:

- net cash proceeds of $383 million, after closing adjustments, received from the Gulf of Mexico asset sale;
- total loss of $249 million on commodity derivative instruments;
- pre-tax income of $7 million, as compared with pre-tax loss of $2.1 billion for second quarter 2017; and
- capital expenditures, excluding acquisitions, of $787 million, as compared with $613 million for second quarter 2017.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2018	2017	2018	2017
Oil, NGL and Gas Sales to Third Parties [1]	$ 1,100	$ 1,017	$ 2,273	$ 2,011
Sales of Purchased Gas [2]	24	—	55	—
Income from Equity Method Investees	36	25	71	52
Total Revenues	1,160	1,042	2,399	2,063
Production Expense [1]	329	309	681	627
Exploration Expense	29	30	64	72
Depreciation, Depletion and Amortization	435	486	880	999
Purchases of Gas [2]	31	—	67	—
Loss on Marcellus Shale Upstream Divestiture	—	2,322	—	2,322
(Loss) Gain on Divestitures [3]	31	—	(361)	—
Asset Impairments [3]	—	—	168	—
Loss (Gain) on Commodity Derivative Instruments	249	(57)	328	(167)
Clayton Williams Energy Acquisition Expenses [3]	—	90	—	94
Income (Loss) Before Income Taxes	7	(2,145)	493	(1,917)

(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. This presentation change resulted in increases to revenues, and corresponding increases to production expense, of $2 million and $7 million for second quarter and the first six 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.

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

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 June 30, 2018							
United States [3]	108	62	467	247	$ 64.67	$ 24.46	$ 2.29
Eastern Mediterranean	—	—	225	38	—	—	5.46
West Africa [4]	17	—	225	54	72.79	—	0.27
Total Consolidated Operations	125	62	917	339	65.77	24.46	2.57
Equity Investees [5]	2	5	—	7	76.07	43.36	—
Total	127	67	917	346	$ 65.93	$ 25.90	$ 2.57
Three Months Ended June 30, 2017							
United States	110	63	736	296	$ 45.78	$ 18.79	$ 3.20
Eastern Mediterranean	—	—	272	46	—	—	5.34
West Africa [4]	22	—	231	60	49.53	—	0.27
Total Consolidated Operations	132	63	1,239	402	46.40	18.79	3.13
Equity Investees [5]	2	4	—	6	50.93	34.46	—
Total	134	67	1,239	408	$ 46.49	$ 19.84	$ 3.13
Six Months Ended June 30, 2018							
United States [3]	115	63	486	259	$ 63.23	$ 25.00	$ 2.47
Eastern Mediterranean	—	—	243	41	—	—	5.47
West Africa [4]	16	—	215	51	70.65	—	0.27
Total Consolidated Operations	131	63	944	351	64.13	25.00	2.74
Equity Investees [5]	2	5	—	7	71.56	41.61	—
Total	133	68	944	358	$ 64.22	$ 26.27	$ 2.74
Six Months Ended June 30, 2017							
United States	105	56	733	283	$ 47.31	$ 21.04	$ 3.32
Eastern Mediterranean	—	—	272	46	—	—	5.33
West Africa [4]	20	—	237	59	51.28	—	0.27
Total Consolidated Operations	125	56	1,242	388	47.95	21.04	3.18
Equity Investees [5]	2	5	—	7	51.71	35.38	—
Total	127	61	1,242	395	$ 48.01	$ 22.29	$ 3.18

(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:

- increases in NGL revenues, and corresponding increases in production expense, of $4 million and $9 million for second quarter 2018 and the first six months of 2018, respectively;
- decreases in natural gas revenues, and corresponding decreases in production expense, of $2 million for both second quarter 2018 and the first six months of 2018;
- increases in NGL and natural gas sales volumes of 5 MBbl/d and 31 MMcf/d, respectively, for both second quarter 2018 and the first six months of 2018, respectively; and
- reductions in average realized NGL and natural gas sales prices of $1.31/Bbl and $0.11/Mcf, respectively, for second quarter 2018 and $1.09/Bbl and $0.10/Mcf, respectively, for the first six 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) Includes 3 MBoe/d and 14 MBoe/d for second quarter and the first six months of 2018, respectively, related to Gulf of Mexico assets sold in April 2018. See Item Financial Statements – Note 3. Acquisitions and Divestitures.

(4) 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.

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

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	NGLs	Natural Gas	Total
Three Months Ended June 30, 2017	$ 557	$ 108	$ 352	$ 1,017
Changes due to				
Decrease in Sales Volumes	(31)	(10)	(107)	(148)
Increase (Decrease) in Sales Prices (1)	223	35	(29)	229
Impact of ASC 606 Adoption	—	4	(2)	2
Three Months Ended June 30, 2018	$ 749	$ 137	$ 214	$ 1,100
Six Months Ended June 30, 2017	$ 1,084	$ 213	$ 714	$ 2,011
Changes due to				
Increase (Decrease) in Sales Volumes	49	1	(192)	(142)
Increase (Decrease) in Sales Prices (1)	389	60	(52)	397
Impact of ASC 606 Adoption	—	9	(2)	7
Six Months Ended June 30, 2018	$ 1,522	$ 283	$ 468	$ 2,273

(1) Changes exclude gains and losses related to commodity derivate instruments.

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

- increases of 42% and 34% for second quarter and the first six months of 2018, respectively, in average realized prices due to the partial rebalancing of global supply and demand factors; and
- higher US onshore sales volumes of 17 MBbl/d and 22 MBbl/d for second quarter and the first six months of 2018, respectively, primarily driven by an increase in development activity in the Delaware Basin and DJ Basin and the Clayton Williams Energy acquisition;

partially offset by:

- lower Gulf of Mexico sales volumes of 19 MBbl/d and 12 MBbl/d for second quarter and the first six months of 2018, respectively, due to natural field decline as well as the sale of the Gulf of Mexico assets in April 2018; and
- lower offshore Equatorial Guinea sales volumes of 5 MBbl/d and 4 MBbl/d for second quarter and the first six months of 2018, respectively, due to natural field decline.

NGL Sales Revenues Revenues from NGL sales increased second quarter and the first six 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 13 MBbl/d (exclusive of 5 MBbl/d from adoption of ASC 606) for second quarter and the first six months of 2018, respectively, primarily attributable to development activities in the southern area of Gates Ranch in the Eagle Ford Shale;
- increases of 37% and 24% in average realized prices for second quarter and the first six months of 2018, respectively, due to the partial rebalancing of domestic supply and demand factors; and
- increases of $4 million and $9 million for second quarter and the first six months of 2018, respectively, associated with the adoption of ASC 606;

partially offset by:

- lower sales volumes of 9 MBbl/d for second quarter and the first six 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 second quarter and the first six months of 2018 as compared with 2017 due to the following:

- lower sales volumes of 331 MMcf/d and 350 MMcf/d for second quarter and the first six months of 2018, respectively, due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;
- lower sales volumes in Israel due to the sale of a 7.5% interest in the Tamar field;
- lower Gulf of Mexico sales volume of 14 MMcf/d and 8 MMcf/d for the second quarter and the first six months of 2018, respectively, due to natural field decline as well as the sale of the Gulf of Mexico assets in April 2018;
- lower sales volumes of 6 MMcf/d and 21 MMcf/d for second quarter and the first six months of 2018, respectively, from the Alba field, offshore Equatorial Guinea, due to natural field decline and timing of field maintenance; and
- decreases of 14% and 10% in average realized prices for second quarter and the first six months of 2018, respectively, 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:

- higher US onshore sales volumes of 53 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606) and 89 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606) the second quarter and the first six months of 2018, respectively, primarily attributable to development activities in the DJ Basin and the southern area of Gates Ranch in the Eagle Ford Shale; and
- higher sales volumes in Israel due to increased demand.

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 are recorded within purchases of gas in our consolidated statements of operations. For second quarter and the first six months of 2018, the net effect of third party purchases and sales of natural gas were losses of $7 million and $12 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 as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, activity is reflected within cash flows provided by operating activities and cash flows provided by (used in) investing activities.

Income from equity method investees increased during the first six months of 2018 as compared with 2017. The increase includes a $6 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee, and a $12 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 June 30, 2018					
Lease Operating Expense (3)	$ 4.47	$ 138	$ 114	$ 5	$ 19
Production and Ad Valorem Taxes	1.56	48	48	—	—
Gathering, Transportation and Processing (4)	4.31	133	133	—	—
Other Royalty Expense	0.33	10	10	—	—
Total Production Expense	$ 10.67	$ 329	$ 305	$ 5	$ 19
Total Production Expense per BOE		$ 10.67	$ 13.55	$ 1.47	$ 3.84
Three Months Ended June 30, 2017					
Lease Operating Expense (3)	$ 3.54	$ 129	$ 105	$ 6	$ 18
Production and Ad Valorem Taxes	0.89	32	32	—	—
Gathering, Transportation and Processing (4)	3.89	142	142	—	—
Other Royalty Expense	0.16	6	6	—	—
Total Production Expense	$ 8.48	$ 309	$ 285	$ 6	$ 18
Total Production Expense per BOE		$ 8.48	$ 10.60	$ 1.46	$ 3.28
Six Months Ended June 30, 2018					
Lease Operating Expense (3)	$ 4.62	$ 293	$ 240	$ 12	$ 41
Production and Ad Valorem Taxes	1.59	101	101	—	—
Gathering, Transportation and Processing (4)	4.10	260	260	—	—
Other Royalty Expense	0.43	27	27	—	—
Total Production Expense	$ 10.74	$ 681	$ 628	$ 12	$ 41
Total Production Expense per BOE		$ 10.74	$ 13.42	$ 1.64	$ 4.39
Six Months Ended June 30, 2017					
Lease Operating Expense (3)	$ 3.78	$ 265	$ 211	$ 14	$ 40
Production and Ad Valorem Taxes	1.03	72	72	—	—
Gathering, Transportation and Processing (4)	3.99	280	280	—	—
Other Royalty Expense	0.14	10	10	—	—
Total Production Expense	$ 8.94	$ 627	$ 573	$ 14	$ 40
Total Production Expense per BOE		$ 8.94	$ 11.20	$ 1.71	$ 3.72

(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 increases of $2 million and $7 million to gathering, transportation and processing expense related to US operations for second quarter and the first six months of 2018, respectively. On a per BOE basis, including the increase in production volumes, the presentation change resulted in decreases of $0.46/Boe and $0.35/Boe for US production expense for the second quarter and the first six 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.

For second quarter and the first six months of 2018, total production expense increased as compared with 2017 due to the following:

- an increase in US lease operating expense primarily due to increased development activities resulting in added production in across each of our onshore US basins;
- an increase in US production and ad valorem taxes due to higher commodity prices;
- an increase in US gathering, transportation and processing expense attributable to development activities in the southern area of Gates Ranch in the Eagle Ford Shale which led to increased sales volumes; and

- an increase in US other royalty expense due to increased commodity market prices;

partially offset by:

- a decrease in first quarter 2018 in US lease operating expense 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; 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.

Production expense on a per BOE basis increased for the second quarter and the first six months of 2018, as compared with 2017 primarily due to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets in second quarter 2017, coupled with an increase in certain production expenses noted above. Specifically, the divestiture of the Marcellus Shale upstream assets removed lower-cost, natural gas-focused sales volumes from our portfolio, while an increase in volumes from the Delaware Basin and Eagle Ford Shale contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE.

Exploration Expense Exploration expense for the first six months of 2018 totaled $64 million, including $24 million of lease rental expense primarily in the Delaware Basin and $27 million of staff expense.

Exploration expense for the first six months of 2017 totaled $72 million, including $18 million of undeveloped leasehold impairment expense related to the impairment of leases in deepwater Gulf of Mexico and $29 million of staff expense.

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 June 30, 2018										
DD&A Expense	$	435	$	394	$	15	$	26	$	—
Unit Rate per BOE (1)	$	14.10	$	17.51	$	4.41	$	5.25	$	—
Three Months Ended June 30, 2017										
DD&A Expense	$	486	$	427	$	19	$	39	$	1
Unit Rate per BOE (1)	$	13.32	$	15.89	$	4.62	$	7.11	$	—
Six Months Ended June 30, 2018										
DD&A Expense	$	880	$	800	$	28	$	52	$	—
Unit Rate per BOE (1)	$	13.87	$	17.10	$	3.82	$	5.56	$	—
Six Months Ended June 30, 2017										
DD&A Expense	$	999	$	886	$	37	$	74	$	2
Unit Rate per BOE (1)	$	14.25	$	17.32	$	4.52	$	6.88	$	—

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

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

- year-end reserve additions, primarily in US onshore due to enhanced well design and completion techniques in our horizontal drilling program as well as reserve additions in the Tamar field due to well results and geological evaluation, and globally due to positive commodity price revisions;
- the Marcellus Shale upstream divestiture in second quarter 2017, which reduced DD&A expense by $99 million and $118 million for second quarter and the first six months of 2018, respectively;
- 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 $62 million and $109 million for second quarter and the first six months of 2018, respectively; and
- reclassification of a 7.5% working interest in the Tamar field, offshore Israel, as asset held for sale at December 31, 2017, resulting in the cessation of DD&A expense and decreases of $3 million and $7 million for second quarter and the first six 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;
- increased development activities in the southern area of Gates Ranch in the Eagle Ford Shale; and
- higher sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The unit rate per BOE for second quarter 2018, as compared with 2017, increased due to increased development activity and capital program in the Delaware Basin resulting in a higher depletable basis. The unit rate per BOE for the first six months of 2018, as compared with 2017, decreased due to the sale of higher-cost production from the Gulf of Mexico assets. This decrease is partially offset by the sale of lower-cost production from the sale of 7.5% Tamar interest in 2018 and the sale of the Marcellus Shale upstream assets in 2017. In addition, an increase in reserves as of December 31, 2017 in Equatorial Guinea also contributed to a decline in unit rate per BOE.

Other Operating Expense, Net See Item 1. Financial Statements – Note 2. Basis of Presentation and Item 1. Financial Statements – Note 11. Segment Information for discussion of other operating expense items for second quarter and the first six months of 2018 as compared with 2017.

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

For the first six months of 2018, loss on commodity derivative instruments included:

- net cash settlement payment of $93 million; and
- net non-cash increase of $235 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 six months of 2017, gain on commodity derivative instruments included:

- net cash settlement receipt of $14 million; and
- net non-cash increase of $153 million in the fair value of our net commodity derivative asset, 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 Note 6. Fair Value Measurements and Disclosures.

MIDSTREAM

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

Results of Operations

Highlights for our Midstream segment were as follows:

Second Quarter 2018 Significant Midstream Operating Highlights Included:

- commenced gathering services in the Mustang IDP area in the DJ Basin;
- completed construction of the Collier and Billy Miner Train II CGFs in the Delaware Basin;

- secured long-term dedications, from existing and new third party customers, for the Black Diamond system, a large, integrated gathering system in the DJ Basin acquired in the Saddle Butte acquisition; and
- received a third party producer's activity set and development plan for Delaware Basin acreage, with gathering services expected to commence in late 2018.

Second Quarter 2018 Midstream Financial Results Included:

- net proceeds of approximately $135 million received, and gain of $109 million recognized, on the sale of a portion of our investment in CNX Midstream Partners common units;
- pre-tax income of $175 million, as compared with pre-tax income of $58 million for second quarter 2017; and
- capital expenditures, excluding acquisitions, of $157 million, as compared with $88 million for second quarter 2017.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2018	2017	2018	2017
Midstream Services Revenues – Third Party	$ 15	$ 4	$ 28	$ 4
Sales of Purchased Oil	42	—	64	—
Income from Equity Method Investees	13	13	25	28
Intersegment Revenues	85	69	166	127
Total Revenues	155	86	283	159
Operating Costs and Expenses	27	23	61	42
Depreciation and Amortization	22	5	38	10
Gain on Divestitures	(109)	—	(305)	—
Purchased Oil	40	—	61	—
Total (Income) Expense	(20)	28	(145)	52
Income Before Income Taxes	$ 175	$ 58	$ 428	$ 107

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 and NGLs in the markets served directly or indirectly by our midstream assets.

Total revenues for second quarter and the first six 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 subsequent to second quarter 2017. 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 second quarter and the first six months of 2018, the net effect of third party purchases and sales of crude oil was de minimis.

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

Depreciation and amortization expense for second quarter and the first six months of 2018 increased from 2017 due to assets placed in service subsequent to first 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 relates to sales of our interest in CONE Gathering and a portion 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 June 30,		Six Months Ended June 30,	
(millions, except unit rate)	2018	2017	2018	2017
G&A Expense	$ 105	$ 103	$ 209	$ 202
Unit Rate per BOE (1)	$ 3.40	$ 2.82	$ 3.29	$ 2.88

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

G&A expense for second quarter and the first six months of 2018 increased as compared with 2017. This increase was driven by increased employee costs and third party fees in support of our development projects, partially offset by a decrease in contractor expenses. The increase in the unit rate per BOE for the first six 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 divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Other Operating Expense, Net See Item 1. Financial Statements – Note 2. Basis of Presentation and Item 1. Financial Statements – Note 11. Segment Information for discussion of other operating expense items for second quarter and the first six months of 2018 as compared with 2017.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except unit rate)	2018	2017	2018	2017
Interest Expense, Gross	$ 91	$ 107	$ 181	$ 206
Capitalized Interest	(18)	(11)	(35)	(23)
Interest Expense, Net	$ 73	$ 96	$ 146	$ 183
Unit Rate per BOE (1)	$ 2.37	$ 2.63	$ 2.30	$ 2.61

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

Interest expense, gross, for second quarter and the first six months of 2018 decreased as compared with 2017 primarily due to a decrease in the overall debt balance. Specifically, subsequent to second quarter 2017, we repaid $550 million on our Term Loan Facility due January 6, 2019 and during the first six months of 2018, we repaid $379 million of Senior Notes due May 1, 2021. In addition, in second quarter 2017, we conducted a tender offer and subsequent redemption of our 8.25% Senior Notes, resulting in a lower interest rate and lower interest expense, gross. These were partially offset by an increase of $445 million in the amount outstanding under our Noble Midstream Services Revolving Credit Facility. See Item 1. Financial Statements - Note 5. Debt.

Capitalized interest for second quarter and the first six months of 2018 increased as compared with 2017 primarily due to higher work in progress amounts related to the Leviathan development. See Item 1. Financial Statements - Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

The unit rate of interest expense, net, per BOE for second quarter and the first six 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, available borrowing capacity under our $4.0 billion unsecured revolving credit facility (Revolving Credit Facility) and proceeds from divestitures of properties. 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. See Operating Outlook – Impact of Recent Changes in US Tax Law.

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 a portion of our investment in CNX Midstream Partners common units. As a result, our divestitures have generated cash proceeds of approximately $3.5 billion during 2017-2018 and were used to improve our capital structure and strengthen our liquidity profile.

We strive to fund our capital program through organic cash flows and, when needed, utilize borrowings under our Revolving Credit Facility.

As of June 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 open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be significant.

Second Quarter and Year-to-Date 2018 Highlights

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

- redemption of $379 million in outstanding senior notes;
- acquisition of 1.8 million shares of Noble Energy stock, for $63 million, resulting in year to date repurchases of 4.0 million shares for $130 million, pursuant to the Board of Directors' authorized $750 million share repurchase program; and
- announcement in July 2018 of an August 2018 dividend of 11 cents per common share, which continues the 10% increase over 2017.

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

- repaid all amounts outstanding under the Revolving Credit Facility;
- extended the Revolving Credit Facility 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 the maturity date of the Noble Midstream Services Revolving Credit Facility by one and a half years to March 2023.

Also, during the first six months of 2018, we repatriated $404 million in payments from foreign operations on an outstanding note payable. This payment eliminates the balance on the note payable and has no US tax impact.

Available Liquidity

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

(millions, except percentages)	June 30, 2018	December 31, 2017
Total Cash [1]	$ 621	$ 713
Amount Available to be Borrowed Under Revolving Credit Facility [2]	4,000	3,770
Total Liquidity	$ 4,621	$ 4,483
Total Debt [3]	$ 6,663	$ 6,859
Noble Energy Share of Equity	10,252	9,936
Ratio of Debt-to-Book Capital [4]	39%	41%

(1) As of June 30, 2018, total cash included cash and cash equivalents of $15 million related to Noble Midstream Partners. 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. 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, 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 $621 million in cash and cash equivalents at June 30, 2018, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $428 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 June 30, 2018, no amounts were outstanding under the Revolving Credit Facility and $530 million was outstanding under the Noble Midstream Services Revolving Credit Facility, leaving $4.0 billion and $270 million in remaining availability under the respective credit facilities. See Item 1. Financial Statements – Note 6. Debt.

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 June 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.

Subsequent Event - Noble Midstream Services Term Credit Agreement On July 31, 2018, Noble Midstream Services, LLC entered into a three year senior unsecured term loan credit facility (Noble Midstream Services Term Credit Agreement) of up to $500 million. Proceeds from the Noble Midstream Services Term Credit Agreement will be used to repay a portion of the outstanding borrowings under the Noble Midstream Services Revolving Credit Facility, pay fees and expenses in connection with the Noble Midstream Services Term Credit Agreement transactions and for working capital, capital expenditures, acquisitions and other purposes as necessary of Noble Midstream Partners and its subsidiaries. See Item 1. Financial Statements – Note 5. Debt.

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 June 30, 2018, we had entered into approximately $235 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 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.

Marcellus Shale Firm Transportation Agreements We have remaining financial commitments of approximately $1.4 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 late 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 $890 million, undiscounted, of the total $1.4 billion commitment noted above. See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

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:

	Six Months Ended June 30,	
(millions)	2018	2017
Total Cash Provided By (Used in)		
Operating Activities	$ 1,079	$ 877
Investing Activities	(1,050)	(1,121)
Financing Activities	(121)	(426)
Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	$ (92)	$ (670)

Operating Activities Cash provided by operating activities increased for the first six months of 2018 compared with 2017 by approximately $202 million. The increase is primarily due to higher realized crude oil prices and an increase in crude oil production in the DJ and Delaware basins. In addition, changes in working capital included a significant increase in the balance of the current portion of the commodity derivatives liability.

These increases were partially offset by lower realized natural gas prices, a decrease in natural gas production attributable to our exit from the Marcellus Shale in second quarter 2017, and higher production costs attributable to increased US onshore activity.

Investing Activities Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions, including farm-out arrangements, which may result in reimbursement for capital spending that occurred in prior periods.

Total additions to property, plant and equipment increased $567 million during the first six 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 primarily in the Marcellus Shale and Eagle Ford Shale. See Operating Outlook – 2018 Capital Investment Program, above.

During the first six months of 2018, we completed certain portfolio activities including the Saddle Butte acquisition for $650 million, net. Also during the first six months of 2018, we received net proceeds of $1.4 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 a portion of our CNX Midstream Partners common units.

In comparison, during the first six months of 2017, we used $637 million of cash to fund a portion of the consideration paid in the Clayton Williams Energy Acquisition and acquired Delaware Basin assets for $301 million. We received net cash proceeds of $1.0 billion from the Marcellus Shale upstream divestiture, and other investing activities provided net cash of $33 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 six months of 2018 included a $230 million, net, Revolving Credit Facility repayment and $445 million, net, Noble Midstream Services Revolving Credit Facility borrowings used primarily to fund an acquisition. We also used $384 million of cash to redeem senior notes which had accrued interest of $11 million and is reflected within operating activities.

In addition, during the first six months of 2018, we made common stock repurchases totaling $130 million pursuant to our stock repurchase program, paid $102 million of cash dividends to Noble Energy shareholders and $22 million of cash distributions to Noble Midstream Partners noncontrolling interest owners. We also received $331 million of contributions from noncontrolling interest owners. Other financing activities used net cash of $29 million.

In comparison, during the first six months of 2017, we borrowed and repaid $1.3 billion under our Revolving Credit Facility and borrowed a net $190 million under the Noble Midstream Services Revolving Credit Facility. We also repaid $595 million of assumed Clayton Williams Energy debt. We used cash of $92 million to pay dividends on our common stock and $12 million to pay distributions to noncontrolling interest owners. We received $138 million of net cash from the issuance of Noble Midstream Partners common units.

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

Dividends On July 24, 2018, our Board of Directors declared a quarterly cash dividend of 11 cents per common share, which will be paid on August 20, 2018 to shareholders of record on August 6, 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 second quarter and the first six months of 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2018	2017	2018	2017
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition (1)	$ —	$ 1,581	$ —	$ 1,826
Proved Property Acquisition (2)	—	782	—	840
Exploration and Development	771	605	1,427	1,199
Midstream (3)	157	152	616	245
Corporate and Other	16	10	27	15
Total	$ 944	$ 3,130	$ 2,070	$ 4,125
Investment in Equity Method Investee (4)	$ —	$ 67	$ —	$ 67

(1) 2017 acquisition costs include $1.6 billion related to the Clayton Williams Energy Acquisition and $246 million related to the Delaware Basin acquisition.
(2) 2017 acquisition costs include $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.
(3) Midstream expenditures for the six months ended June 30, 2018 include $206 million related to the Saddle Butte acquisition. Midstream expenditures for the first six months of 2017 include $67 million related to the Clayton Williams Energy Acquisition.
(4) 2017 costs represent our contribution to the Advantage Joint Venture, in which Noble Midstream Partners owns a 50% interest.

Development costs for second quarter and the first six months of 2018 increased as compared with second quarter and the first six months of 2017 due to increased US onshore activity and Leviathan development activities. Year to date development costs include approximately $1.1 billion for US onshore E&P operations and approximately $350 million for Leviathan. The increase in development costs was partially offset by a decrease due to the 2017 Marcellus Shale divestiture. In addition, midstream capital spending, exclusive of acquisitions, increased 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 June 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 $306 million. Based on the June 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 $280 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 June 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 June 30, 2018, our cash and cash equivalents totaled $621 million, approximately 46% of which was invested in money market funds and short-term investments with major financial institutions.

In addition, borrowings under the Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility and 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 June 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 Noble Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility or Leviathan Term Loan Facility would have a de minimis impact. 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. Furthermore, our investment in Tamar Petroleum is denominated and settled in New Israeli Shekels.

Net transaction gains and losses were de minimis for the second quarter and the first six 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 12. Commitments and Contingencies of this Form 10-Q, which is incorporated by reference into this Part II. Item 1, as well as discussion in Item 3. Legal Proceedings, of our Annual Report on Form 10-K for the year ended December 31, 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.

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)
4/1/2018 - 4/30/2018	216	$	31.72	—		
5/1/2018 - 5/31/2018	837,995		32.84	837,418		
6/1/2018 - 6/30/2018	941,779		35.65	941,502		
Total	1,779,990	$	34.33	1,778,920	$	620

(1) Includes stock repurchases of 1,070 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 second quarter 2018, we repurchased and retired 1.8 million shares of common stock at an average purchase price of $35.15 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 herewith.
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

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** 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 August 3, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Executive Vice President, Chief Financial Officer

Exhibit 10.1

NOBLE ENERGY, INC.
SHORT-TERM INCENTIVE PLAN

ARTICLE I. ESTABLISHMENT AND PURPOSE

1.1 Establishment. Noble Energy, Inc., a Delaware corporation ("**Noble**"), hereby establishes the Noble Energy, Inc. Short-Term Incentive Plan for the benefit of certain employees.

1.2 Purpose. The purpose of this Plan is to provide cash incentive compensation opportunities for eligible employees of an Employer. The Plan is designed to provide a competitive bonus to eligible employees to assist in the attraction, motivation, and retention of superior talent, and to align such employees' interests with those of the Employer and its stockholders through the achievement of established performance goals attributable to a Plan Year.

1.3 Effective Date. This Plan shall become effective on January 1, 2018 (the "**Effective Date**").

ARTICLE II. DEFINITIONS

2.1 "**Affiliate**" means any corporation or other type of entity in a chain of corporations or other entities in which each corporation or other entity has a controlling interest in another corporation or other entity in the chain, starting with Noble and ending with the corporation or other entity that has a controlling interest in the corporation or other entity for which the employee provides direct services.

2.2 "**Award**" means a cash bonus award granted to a Participant under the Plan for a Plan Year.

2.3 "**Award Payment Date**" means the date upon which payment of an Award is actually made to a Participant, which date shall be selected by the Company or the Committee; provided, however, the Award Payment Date shall be no later than the last day of the calendar year immediately following the Plan Year for which the Award is attributable.

2.4 "**Base Salary**" means the Participant's (a) annual base salary as in effect at the end of the Plan Year for exempt employees and/or (b) annualized base salary as in effect at the end of the Plan Year, plus overtime worked during the Plan Year, for non-exempt employees.

2.5 "**Board**" means the Board of Directors of Noble.

2.6 "**Bonus Pool Factor**" means the percentage, within the range of 0% to 250%, as determined by the Committee in its discretion, to be effective for a Plan Year.

2.7 "**CEO**" means the then-current Chief Executive Officer of Noble.

2.8 "**Code**" means the Internal Revenue Code of 1986, as amended, including regulations and other authoritative guidance thereunder and successor provisions thereto.

2.9 "**Committee**" means the Compensation, Benefits and Stock Option Committee of the Board or such other delegate of the Board as may be designated by the Board from time to time to administer the Plan.

2.10 "**Company**" means Noble.

2.11 "**Employer**" means the Company and any Affiliate that has adopted this Plan with the consent of the Company.

2.12 "**Noble**" means Noble Energy, Inc., a Delaware corporation, or any successor thereto.

2.13 "**Participant**" means an individual who is an employee of an Employer, as designated on its payroll records, who has been granted an Award.

2.14 "**Plan**" means the Noble Energy, Inc. Short-Term Incentive Plan, as it may be amended from time to time.

2.15 "**Plan Year**" means a calendar year, with the first Plan Year commencing on the Effective Date.

2.16 "**Section 409A**" means Section 409A of the Code.

2.17 "**Target Bonus Percentage**" means the percentage of Base Salary established for a Participant that is considered in determining the amount of a Participant's Award for a Plan Year. Target Bonus Percentages and adjustments (a) for executives are made by the Committee in its discretion and (b) for non-executives are made by the CEO or CEO's delegate in his or her discretion. The Target Bonus Percentage utilized for a Participant is the Target Bonus Percentage in effect at the end of the applicable Plan Year.

ARTICLE III. PLAN ADMINISTRATION

3.1 Plan Administrator and Discretionary Authority. This Plan shall be administered by the Committee. The Committee shall have total and exclusive responsibility to control, operate, manage and administer this Plan in accordance with its terms. The Committee shall have all the authority that may be necessary or helpful to enable it to discharge its responsibilities with respect to this Plan. Without limiting the generality of the preceding sentence, the Committee shall have the exclusive right to (a) interpret this Plan, (b) decide all questions concerning eligibility for, and the amount of, Awards granted or paid under this Plan, (c) construe any ambiguous provision of this Plan, (d) correct any defect, supply any omission or reconcile any inconsistency in this Plan, (e) issue administrative guidelines as an aid in administering this Plan and make changes in such guidelines as the Committee from time to time deems proper, (f) make regulations for carrying out this Plan and make changes to such regulations as the Committee from time to time deems proper, (g) to the extent permitted under this Plan, grant waivers of Plan terms, conditions, restrictions and limitations, and (h) take any and all other actions that the Committee deems to be necessary or advisable for the proper operation or administration of this Plan. The Committee shall have authority, in its sole discretion, with respect to all matters related to the discharge of its responsibilities and the exercise of its authority under this Plan, including without limitation, its construction of the terms of this Plan and its determination of eligibility for participation in, and the terms of Awards granted under, this Plan. It is at the discretion of the Committee whether there will be any Awards granted under this Plan during any Plan Year. There is no guarantee that any Awards will be granted regardless of Company, Employer, or individual performance. The decisions of the Committee and its actions with respect to this Plan shall be final, conclusive and binding on all persons having or claiming to have any right or interest in or under this Plan.

3.2 Delegation of Authority. The Committee shall have the authority, in its discretion, to delegate its duties and functions under the Plan to the CEO or any other officer of an Employer, other members or committees of the Board, or such other agents as it may appoint from time to time; provided, however, the Committee may not delegate a duty hereunder where such delegation would: (a) violate applicable law, or (b) would determine the amount of an Award to a Named Executive Officer as identified in the Proxy Statement for the applicable Plan Year.

3.3 Liability; Indemnification. No member of the Committee or the CEO, nor any person to whom the Committee or CEO has delegated any authority under the Plan, shall be personally liable for any action, interpretation or determination made in good faith with respect to the Plan or any Award. Each current or former member of the Committee and the CEO, and any current or former employee of the Company or an Affiliate who has been delegated a duty by the Committee or CEO hereunder, shall be fully indemnified, defended and held harmless by the Company with respect to any liability, cost or damage that he or she may incur with respect to any such action, interpretation or determination made in good faith under the Plan, to the maximum extent permitted by applicable law. This indemnification, defense and hold harmless obligation of the Company shall be in addition to, and shall not supersede or replace, any other indemnification policy or agreement that covers such individual.

ARTICLE IV. ELIGIBILITY

4.1 Employment During Plan Year. Subject to the provisions of this Article IV, for any particular Plan Year all regular employees of an Employer are eligible to participate in the Plan if employed during the Plan Year. Temporary employees, interns, contractors, and authorized agents are not eligible to participate in the Plan. Awards for any such employees who first become Participants after the first day of the Plan Year will be prorated for the portion of such Plan Year that Participant was employed by an Employer.

4.2 Employment on Award Payment Date. A Participant must remain continuously employed by the Company or Affiliate through the Award Payment Date in order to be eligible to receive an Award for such Plan Year, except as provided in Section 4.4. A Participant whose employment with the Company or Affiliate has terminated prior to the Award Payment Date for any reason, other than as set forth in Section 4.4, is not eligible to receive any Award, or portion thereof, for such Plan Year.

4.3 Satisfactory Performance. A Participant must maintain satisfactory performance, as determined by the Company, in order to be eligible for an Award for a Plan Year. Participants who have been placed on a Performance Improvement Plan or equivalent ("**PIP**") may be suspended from participating in the Plan for the period of time that the Participant is on the PIP. A Participant may be reinstated as an eligible Participant under the Plan if performance improves. Suspension and reinstatement determinations will be made in the discretion of the applicable department Vice President (or Executive Officer if there is no department Vice President). Participants will be notified in writing when their eligibility from the Plan is suspended and/or reinstated. A Participant who is suspended for part of a Plan Year may be eligible to receive a partial prorated Award for such Plan Year.

4.4 Death of Participant. Any Participant whose employment with the Employer is terminated during a Plan Year, or thereafter prior to the Award Payment Date for such Plan Year, due to the Participant's death shall remain eligible to receive payment under an Award for such Plan Year. If the Participant's death occurs prior to the end of the Plan Year, the amount of the Award shall be prorated to the date of death and determined by the Committee or its delegate in its discretion. In the event of a Participant's death, payment shall be made to the Participant's estate as soon as administratively practicable following the end of the Plan Year containing the date of death, but only after proper instructions have been received by the Company from the legally appointed representative or executor of the Participant's estate.

4.5 Approved Leaves of Absence. A Participant who takes an approved leave of absence will continue to be eligible to participate in the Plan for up to the first three (3) months of the approved leave period. When permitted by applicable law, Participants will be suspended from participating in the Plan for the remainder of their approved leave period exceeding the first three (3) months. A Participant who is suspended for part of a Plan Year may be eligible to receive a partial prorated Award for such Plan Year.

4.6 Prorated Awards. In the event that a Participant is determined to be eligible for a prorated Award for a Plan Year, such proration shall be determined based on the number of days during the Plan Year for which the Participant was eligible to participate in the Plan.

ARTICLE V. AMOUNT OF AWARDS

5.1 Performance Goals. Each Plan Year, senior management of the Company will prepare and present to the Committee its recommendations with regard to the performance objectives to be considered for purposes of the Plan for such Plan Year. The performance measure(s) to be used for purposes of Awards shall be set in the Committee's discretion. The performance measures may consist of one or more operating, financial, safety, and/or market-based criteria. The performance goals based on these performance measures may also be made relative to the performance of other business entities.

5.2 Target Performance Levels. Based upon the recommendations of management and such other factors as the Committee may determine and utilize in its discretion, the Committee shall determine the performance goals for each Plan Year and the target level of performance for each performance goal.

5.3 Modifying Performance Goals and Target Levels. At any time during the Plan Year, the Committee may, in its discretion, cancel or revise its determination for such Plan Year made with respect to the performance goals or the target level of performance for each performance goal.

5.4 Bonus Pool Factor. After the end of each Plan Year, the Committee will review the performance results for each performance goal and its target level of performance. Based upon those results, the Committee will determine and then approve or modify the applicable Bonus Pool Factor.

5.5 Individual Participant Awards. Following the determination of the Bonus Pool Factor, Awards for the respective Plan Year will be determined by multiplying the Participant's Base Salary by the Participant's Target Bonus Percentage multiplied by the applicable Bonus Pool Factor, which product will be subject to proration, if applicable, as provided in Article IV, and then further adjusted for such individual, group, or other performance factors as the Committee or its delegate determines are appropriate in its discretion. If a Participant changes employment status during the Plan Year (*e.g.* between full time and part time, etc.) and where permitted by applicable law, the Participant's Award (before any applicable proration and/or further adjustments) may be adjusted to reflect a weighted average of the annualized Awards the Participant would be eligible for under each employment status, weighted by the portion of the Plan Year the Participant was in each employment status.

ARTICLE VI. PAYMENT OF AWARDS

6.1 Award Payment Date. Awards under the Plan shall be paid in one lump sum cash payment by the Employer on the Award Payment Date. No payment of any Award shall be made or owed to any individual who is no longer employed by the Company or Affiliate on the Award Payment Date, except in the case of a Participant's death as provided in Section 4.4.

6.2 Withholdings from Award. The Employer shall be entitled to deduct from any payment made under this Plan the amount of all applicable income taxes, employment taxes, and other deductions or offsets required or authorized by law to be made or withheld with respect to such payment.

ARTICLE VII. AMENDMENT AND TERMINATION

7.1 Plan Amendment and Termination. The Committee shall have the exclusive right and authority to amend, modify, suspend, or terminate the Plan, at any time in its complete discretion, with or without notice to any Participant.

ARTICLE VIII. MISCELLANEOUS

8.1 Compliance with Law. It is intended that payments under the Plan will satisfy, to the full extent possible, the exemption from the application of Section 409A (and any state law of similar effect) provided under Treasury Regulation Section 1.409A-l (b)(4) or any successor thereto (a "short-term deferral"). Any provisions of the Plan that are subject to Section 409A are intended to comply with all applicable requirements of Section 409A, or an exemption from the application of Section 409A, and shall be interpreted and administered accordingly. Any provision of this Plan to the contrary notwithstanding, the Committee may revoke any Award if it is contrary to any applicable law or governmental regulation, or modify an Award to bring it into compliance with any applicable law or government regulation, to the full extent permitted by applicable law or regulation.

8.2 Binding Effect. The obligations of the Company under this Plan shall be binding upon any successor corporation or organization resulting from the merger, consolidation or other reorganization of the Company, or upon any successor corporation or organization succeeding to all or substantially all of the assets and business of the Company. The terms and provisions of this Plan shall be binding upon each Participant, and his or her heirs, legatees, distributes, executors and legal representatives.

8.3 Nonalienation of Benefits. No right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or charge by any Participant (or any beneficiary thereof), and any attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge the same shall be void and without effect. No right or benefit hereunder shall in any manner be liable for or subject to any debts, contracts, liabilities or torts of the person entitled to such benefit unless and until actually received by such person.

8.4 Severability. If any provision of this Plan is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions of this Plan, but such provision shall be fully severable and this Plan shall be construed and enforced as if the illegal or invalid provision had not been included herein or therein.

8.5 No Restriction of Corporate Action. Nothing contained in this Plan shall be construed to prevent the Company or any Affiliate from taking any corporate action (including any corporate action to suspend, terminate, amend or modify this Plan) that is deemed by the Company or such Affiliate to be appropriate or in its best interest, whether or not such action would have an adverse effect on this Plan or on any Awards made or to be made under this Plan. No Participant or other person shall have any claim against the Company or any Affiliate as a result of any such action.

8.6 Governing Law. This Plan shall be governed by and construed in accordance with the internal laws (and not the principles relating to conflicts of laws) of the State of Texas except as may be superseded by applicable federal law, and venue of any action or proceeding relating to, or arising out of, the Plan shall be exclusively in any court of competent jurisdiction situated in Harris County, Texas.

8.7 No Guarantee of Tax Consequences. No person connected with this Plan in any capacity, including without limitation the Employer, Committee and CEO, and their respective directors, officers, members, agents and employees, makes any representation, commitment or guarantee that any tax treatment, including without limitation federal, state and local income, estate and gift tax treatment, will be applicable with respect to any Award or payment made for the benefit of a Participant under this Plan.

8.8 Continued Employment or Service. Nothing contained in this Plan shall confer upon any Employee the right or continued right to be a Participant for any Plan Year or the right to continue in the employ or service of the Company or an Affiliate. In addition, nothing herein shall interfere in any way with the rights of the Company or Affiliate to terminate a Participant's employment or service at any time, with or without cause, or interfere in any way with the right of the Company or an Affiliate to increase or decrease the compensation (including Awards) of any employee or Participant. In addition, nothing contained in this Plan shall (a) be evidence of any agreement or understanding, express or implied, that the Employer will employ a Participant in any particular position, at any particular rate of remuneration, or for any particular time period; or (b) create a fiduciary relationship between a Participant and the Employer or Committee.

8.9 General Creditor Status. The Plan is intended to constitute an unfunded bonus program that is not subject to the Employee Retirement Income Security Act of 1974, as amended ("**ERISA**"). No Participant shall have any lien on or rights with respect to any assets of the Company or any other entity, including any Affiliate, and the Participant's right, if any, to receive payment for an Award shall be no greater than those of a general creditor of the Employer that employs such Participant.

8.10 Modification. The adoption of the Plan, and any modification or amendment of the Plan, does not imply any commitment to continue or adopt the same plan, or any such modification, or any other plan for incentive compensation for any succeeding year. This Plan is intended to be the sole and exclusive short-term incentive plan of each Employer and supersedes any short-term incentive plans, annual bonus plans, or similar arrangements previously adopted by the Employer in their entirety, and all such prior plans and arrangements are hereby null and void and of no further force or effect as of the Effective Date.

8.11 Miscellaneous. Headings are given to the articles and sections of this Plan solely as a convenience to facilitate reference. Such headings shall not be deemed in any way material or relevant to the construction of this Plan or any provisions hereof. The use of the masculine gender shall also include within its meaning the feminine. Wherever the context of this Plan dictates, the use of the singular shall also include within its meaning the plural, and vice versa.

IN WITNESS WHEREOF, this Plan has been approved and executed on this 25th day of July 2018, to be effective as of the Effective Date.

NOBLE ENERGY, INC.

BY: /s/ David L. Stover
Name: David L. Stover
Title: Chairman of the Board, President, and
Chief Executive Officer

EXHIBIT 12.1

Noble Energy, Inc.

Calculation of Ratio of Earnings to Fixed Charges

	Six Months Ended June 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	$ 420	$ (2,436)	$ (1,887)	$ (2,309)	$ 1,540	$ 1,138
Add (Deduct)						
Fixed Charges	195	426	440	435	349	296
Capitalized Interest	(35)	(49)	(84)	(144)	(116)	(121)
Distributed Income From Equity Investees	85	139	83	77	226	204
Earnings (Loss) as Defined	$ 665	$ (1,920)	$ (1,448)	$ (1,941)	$ 1,999	$ 1,517
Net Interest Expense	146	354	328	263	210	158
Capitalized Interest	35	49	84	144	116	121
Interest Portion of Rental Expense	14	23	28	28	23	17
Fixed Charges as Defined	$ 195	$ 426	$ 440	$ 435	$ 349	$ 296
Ratio of Earnings to Fixed Charges	3.4	—	—	—	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: August 3, 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: August 3, 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 June 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:	August 3, 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 June 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: August 3, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer