NOBLE ENERGY INC
Form 10-K
February 19, 2019

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utreg:acre nbl:project utreg:bbl nbl:payment nbl:simulation utreg:MMBTU utreg:D

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

FORM 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018
or
o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from_____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State of incorporation)	(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)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ý Yes o No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes ý No

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. ý Yes o No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ý Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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 definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company”, and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o Emerging growth company o

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. o

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2018: $17.0 billion.

Number of shares of Common Stock outstanding as of December 31, 2018: 477,643,425.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant’s definitive proxy statement for the2019 Annual Meeting of Shareholders to be held on April 23, 2019, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2018, are incorporated by reference into Part III.

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Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K and the documents incorporated by reference in this report contain 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 and development activities;
- our ability to successfully and economically explore for and develop crude oil, natural gas liquids (NGLs) and natural gas resources;
- anticipated trends in our business;
- market conditions in the oil and gas industry;
- the impact of governmental regulation, including United States (US) federal, state, local, and foreign host government tax regulations, fiscal policies and terms, as well as that involving the protection of the environment or marketing of production and other regulations;
- our ability to make and integrate acquisitions or execute divestitures; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management’s 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 and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

PART I

Items 1. and 2. Business and Properties

In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy, Inc. and its subsidiaries (Noble Energy, the Company, we or us). All references to production, sales volumes and reserves quantities are net to our interest unless otherwise indicated. For a summary of commonly used industry terms and abbreviations used in this report, see the Glossary, located at the end of this report.

Noble Energy (NYSE: NBL) is an independent oil and natural gas exploration and production company committed to meeting the world’s growing energy needs and delivering competitive returns to its shareholders. Founded in 1932 and incorporated in Delaware in 1969, Noble Energy is guided by its values, its commitment to safety, and respect for stakeholders, communities and the environment. For more information on how the Company fulfills its purpose: *Energizing the World, Bettering People's Lives®,* visit https://www.nblenergy.com. Information on our website is not incorporated by reference into, and does not constitute a part of, this report.

Portfolio Our portfolio of assets is diversified through US and international projects and production mix among crude oil, NGLs and natural gas. In particular, our business is focused on both US onshore unconventional basins and certain global offshore conventional basins in the Eastern Mediterranean and off the west coast of Africa. In US onshore unconventional basins, we have demonstrated our ability to apply geological, drilling, completion, and midstream design and operational expertise. In US onshore, we utilize an Integrated Development Plan (IDP) which applies a major project development approach to an unconventional basin. In the global offshore, we have had notable exploration and major project successes, which have led to major development projects and provided long-lived cash flows to our business.

Capital Program Looking ahead, approximately 70% of our 2019 capital program (excluding capital funded by Noble Midstream Partners and acquisition capital related to the EMG Pipeline) is allocated to US onshore development, primarily focused on liquids-rich opportunities in the Delaware Basin, Denver-Julesburg (DJ) Basin, and Eagle Ford Shale. Eastern Mediterranean capital expenditures, including remaining costs associated with the Leviathan project, represent approximately 20% of the total. The remaining portion of the capital program is designated for the drilling of a crude oil development well in West Africa, and other exploration and corporate activities. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2019 Capital Investment Program.

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Reportable Segments We manage our operations by geographic region and the nature of the products and services we offer. We have the following reportable segments: United States, Eastern Mediterranean, West Africa, Other International and Midstream. The geographical reportable segments are in the business of crude oil and natural gas acquisition and exploration, development, and production (Oil and Gas Exploration and Production). The Midstream reportable segment develops, owns, and operates domestic midstream infrastructure assets, as well as invests in other financially attractive midstream projects, with current focus areas being the DJ and Delaware Basins. See Item 8. Financial Statements and Supplementary Data – Note 3. Segment Information.

Divestiture and Acquisition Activities We maintain an active portfolio management program which includes divestitures of assets through asset or equity sales, exchanges or other transactions. Our portfolio transformation executed over the past few years has included divestitures of Gulf of Mexico assets, a 7.5% working interest in Tamar, our 50% interest in CONE Gathering LLC, our investment in CNX Midstream Partners common units, and other non-core US onshore assets. As a result, our divestitures generated cash proceeds of $2.0 billion and $2.1 billion in 2018 and 2017, respectively, which were used to improve our capital structure, fund a portion of our capital program, strengthen our liquidity and return value to shareholders through the share repurchase program. We expect active portfolio management to continue as an element in our strategic program.

Periodically, we may also engage in acquisitions of additional crude oil or natural gas properties and related assets through either direct acquisitions of the assets or acquisitions of entities that own the assets. For example, in January 2018, Noble Midstream Partners LP (Noble Midstream Partners) acquired an interest in Black Diamond (defined below) which completed the acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte), and in 2017 we completed the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy). See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources and Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Oil and Gas Properties and Activities We search for crude oil and natural gas properties onshore and offshore, and seek to acquire exploration rights and conduct exploration activities in areas of interest. Our activities include geophysical and geological evaluation; analysis of commercial, regulatory and political risks; and exploratory and development drilling leading to production, where appropriate.

Our current portfolio consists primarily of interests in developed and undeveloped crude oil and natural gas leases and concessions. These properties contribute all of our crude oil, NGL and natural gas production, provide additional investment opportunities in proved areas, and offer further exploration opportunities. Our new venture areas provide frontier exploration opportunities, which may result in the establishment of new operational areas in the future. We also own or invest in midstream assets primarily used in the gathering, processing and transportation of our US onshore production. See Midstream – Properties and Activities.

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The map below illustrates the locations of our significant crude oil and natural gas exploration and production activities:

Development Activities Our development projects have resulted from both exploration success as well as periodic leasing activities which provide entrance to low cost assets. These projects provide opportunities for growth at attractive financial returns. Each project progresses, as appropriate, through the various development phases including appraisal, engineering and design, development drilling, construction and production. While development projects require significant capital investments, typically over a multi-year period, they are expected to offer sustained cash flows during production.

In US onshore, our low production-risk development programs are centered around IDPs and generate efficiencies for upstream and midstream development. IDPs are generally areas of highly contiguous acreage, typically held by production, that accommodate drilling long lateral wells, and other operational synergies. The approach also benefits from the ability to accommodate a flexible capital investment program that can be varied in response to changes in the commodity price environment. We continue to enhance project performance in these areas through design, technology and operational efficiencies.

Offshore, we engage in long-cycle development projects, such as progressing development at the Leviathan natural gas field, offshore Israel, the largest natural gas discovery in our history, and advancing Aseng crude oil development and Alen natural gas monetization in West Africa. Our development activities are discussed in more detail in the sections below.

Exploration Activities We primarily focus on organic growth from exploration and development drilling activities, concentrating on existing basins or plays where we believe we have strategic competitive advantages or in new basins with attractive geological potential and the opportunity for competitive project financial returns. These advantages are derived from proprietary seismic data and operational expertise, which we believe will generate superior returns over the oil and gas business cycle. We have had substantial historic exploration success in the Levant Basin offshore Eastern Mediterranean and the Douala Basin offshore West Africa, resulting in the successful completion of numerous major development projects. In 2018, we conducted limited exploration activities as we focused our capital expenditures on the development of the Leviathan field and US onshore assets.

Goodwill Impairment During fourth quarter 2018, primarily resulting from the drop in West Texas Intermediate index (WTI) strip pricing at the end of 2018, we determined that goodwill of $1.3 billion, which had arisen from the Clayton Williams Energy Acquisition, had been fully impaired. We recorded a charge of $1.3 billion. See Item 8. Financial Statements and Supplementary Data – Note 6. Goodwill Impairment.

Proved Reserves Disclosures

Proved Oil and Gas Reserves Proved reserves at December 31, 2018 were as follows:

Reserves Category	Crude Oil and Condensate (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)[1]	(Percent)
Proved Developed					
United States	165	121	929	442	59 %
Israel	2	—	1,295	218	29 %
Equatorial Guinea	26	9	355	94	12 %
Total Proved Developed Reserves	193	130	2,579	754	100 %
Proved Undeveloped					
United States	255	136	1,015	560	48 %
Israel	6	—	3,635	612	52 %
Equatorial Guinea	3	—	2	3	— %
Total Proved Undeveloped Reserves	264	136	4,652	1,175	100 %
Total Proved Reserves	457	266	7,231	1,929	

[1] Million barrels oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for US natural gas and NGLs is 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.

Our proved reserves totaled 1,929 MMBoe as of December 31, 2018 as compared with 1,965 MMBoe as of December 31, 2017. Our proved reserves are 52% US and 48% international, and the commodity mix is 37% global liquids (crude oil and NGLs), 46% international natural gas and 17% US natural gas.

We have historically added reserves through our exploration program, development activities, and acquisition of producing properties. Changes in proved reserves were as follows:

(MMBoe)	Year Ended December 31, 2018	2017	2016
Proved Reserves Beginning of Year	1,965	1,437	1,421
Revisions of Previous Estimates	(2)	135	64
Extensions, Discoveries and Other Additions	223	736	179
Purchase of Minerals in Place	—	57	4
Sale of Minerals in Place	(128)	(261)	(77)
Production	(129)	(139)	(154)
Proved Reserves End of Year	1,929	1,965	1,437

For a discussion of changes in proved reserves, see Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Proved Undeveloped Reserves (PUDs) As of December 31, 2018, our PUDs totaled 1,175 MMBoe, or 61% of proved reserves. Changes in PUDs were as follows for the year ended December 31, 2018.

(MMBoe)	United States	Israel	Equatorial Guinea	Total
Proved Undeveloped Reserves, Beginning of Year	482	615	—	1,097
Revisions of Previous Estimates	(23)	—	—	(23)
Extensions, Discoveries and Other Additions	181	12	3	196
Sale of Minerals in Place	—	(15)	—	(15)
Conversion to Proved Developed	(80)	—	—	(80)
Proved Undeveloped Reserves, End of Year	560	612	3	1,175

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Revisions of Previous Estimates PUD revisions included:

- *Price Revisions* US onshore positive price revisions (price impact to opening balance) of 3 MMBoe were due to changes in 12-month average commodity prices.
- *Non-Price Revisions* Positive price revisions were offset by negative non-price revisions of 26 MMBoe, including the following:
- the DJ Basin included a positive 8 MMBoe non-price revision, which included a positive revision of approximately 24 MMBoe associated with the adoption of Accounting Standards Codification (ASC) 606, *Revenues from Contracts with Customers* (ASC 606), partially offset by a negative revision of 16 MMBoe due to removal of PUDs locations due to changes in the previously adopted development plan;
- the Delaware Basin included a negative 25 MMBoe non-price revision primarily due to changes in expected recoveries and higher operating and capital costs; and
- the Eagle Ford Shale included a negative 9 MMBoe non-price revision primarily due to removal of PUDs locations due to changes in the previously adopted development plan.

Extensions, Discoveries and Other Additions Extensions of proved reserves were primarily due to drilling plans for new wells, of which 94 MMBoe, 69 MMBoe, 18 MMBoe, 12 MMBoe and 3 MMBoe were in the DJ Basin, Delaware Basin, Eagle Ford Shale, Tamar field and Equatorial Guinea, respectively.

US PUDs Locations During the year, we converted 80 MMBoe of our US PUDs, or 17% of our US PUDs beginning balance, to developed status. The majority of these conversions were in the DJ Basin and Delaware Basin. PUDs conversions were less than 20% in 2018 as we allocated a portion of capital to convert unproved reserves for acreage delineation and lease retention, primarily in the Delaware Basin. In 2018, capital spent to convert approximately 25 MMBoe of unproved reserves to proved developed was approximately $355 million. Based on our current inventory of identified horizontal well locations and our anticipated rate of drilling and completion activity, we expect our US PUDs recorded as of December 31, 2018 to be converted to proved developed reserves within five years of initial recognition.

Our PUDs are expected to be recovered from new wells on undrilled acreage or from existing wells where additional capital expenditures are required for completion, such as drilled but uncompleted (DUC) wells. As of December 31, 2018, 99 MMBoe of PUDs were associated with US onshore DUC well locations, with 42%, 33% and 25% of locations in the DJ Basin, Delaware Basin and Eagle Ford Shale, respectively.

International PUDs Locations PUDs in the Tamar field decreased 15 MMBoe due to the first quarter 2018 sale of a 7.5% working interest. The PUDs in our Tamar Southwest field represent less than 5% of our international PUDs. These PUDs are expected to remain undeveloped for five years or longer since initial disclosure in 2013. We have been working with the government of Israel for final approval of the development plan, which we received in January 2019, and have progressed capital investment within this field, including laying subsea equipment for future tie-in of field production into existing Tamar infrastructure. Other than the Tamar Southwest PUDs, we expect all of our international PUDs, including the 551 MMBoe associated with the initial phase of development of the Leviathan field, to be converted to proved developed reserves within five years of initial recognition.

Development Costs Costs incurred to convert PUDs to proved developed reserves were approximately $1.0 billion in 2018, $1.2 billion in 2017, and $656 million in 2016. Costs incurred in 2018 primarily related to the DJ Basin and Delaware Basin development projects. In addition, we incurred approximately $646 million and $416 million in 2018 and 2017, respectively, to advance the development of the Leviathan PUDs, which are expected to be converted to proved developed reserves with project start up by the end of 2019.

Estimated future development costs relating to the development of all PUDs are projected to be approximately $2.1 billion in 2019, $1.5 billion in 2020, and $1.1 billion in 2021. Estimated future development costs include capital spending on development projects and PUDs related to development projects will be reclassified to proved developed reserves when production commences.

Drilling Plans Our long-range development plans will result in the conversion of all PUDs to developed reserves within five years of their initial recognition, with the exception of the previously mentioned Tamar Southwest PUDs. PUDs associated with the Tamar Southwest field are expected to be converted to proved developed reserves prior to

the end of 2020 as contemplated in our long-range development plan. Initial production from all PUDs is expected to begin during the years 2019 to 2023.
In accordance with US GAAP, we disclose a standardized measure of discounted future net cash flows related to our proved reserves. In order to standardize the measure, all companies are required to use a 10% discount rate and Securities and Exchange Commission (SEC) pricing rules. This prescribed calculation can result in some PUDs having negative present worth, meaning while these PUDs have positive cash flows, the rate of return is lower than 10%. As of December 31, 2018, we had no PUDs with a negative present worth when discounted at 10%.

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We consider the economic development of reserves based on our estimates of future pricing, future investments, production and other economic factors that are excluded from the SEC reserves requirements and are committed to developing PUDs within five years of initial recognition. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2019 Capital Investment Program. For further information on our reserves, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – E&P – Revenues, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Reserves, Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Internal Controls Over Reserves Estimates Our policies and processes regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our internal controls over reserves estimates also include the following:

- the Audit Committee of our Board of Directors reviews significant reserves changes on an annual basis;
- fields that meet a minimum reserve quantity threshold, which combined represent over 80% of our proved reserves, are audited by Netherland, Sewell & Associates, Inc. (NSAI), a third-party petroleum consulting firm, on an annual basis; and
- NSAI is engaged by, and has direct access to, the Audit Committee.

See *Third-Party Reserves Audit*, below.

Responsibility for compliance in reserves estimation is delegated to our Corporate Reservoir Engineering group. Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our geographical regions. These reserves estimates are reviewed and approved by management and senior engineering staff with final approval by the Senior Vice President – Corporate Development and certain other members of senior management.

Our Senior Vice President – Corporate Development oversees our corporate business development, strategic planning and reserves departments. He is the technical person primarily responsible for overseeing the preparation of our reserves estimates and the third-party audit of our reserves estimates. He has Bachelor of Science and Master of Science degrees in Petroleum Engineering and over 38 years of industry experience. Since 2008, he has worked with positions of increasing responsibility in engineering, evaluations and business unit management at the Company. The Senior Vice President – Corporate Development reports directly to our Chief Executive Officer.

Technologies Used in Reserves Estimation The SEC's reserves rules allow the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

We used a combination of production and pressure performance, wireline wellbore measurements, simulation studies, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs and core data to calculate our reserves estimates.

Based on reasonable certainty of reservoir continuity in US onshore formations where we operate, we may record proved reserves associated with wells more than one offset location away from an existing proved producing well. All of our wells drilled that were more than one offset away from a proved producing well at the time of drilling were determined to be economically producible.

Third-Party Reserves Audit In each of the years 2018, 2017, and 2016, we retained NSAI to perform audits of proved reserves. The reserves audit for 2018 included a detailed review of six of our major US onshore and international fields, which covered approximately 98% of total proved reserves.

In connection with the 2018 reserves audit, NSAI prepared its own estimates of our proved reserves and compared its estimates to those prepared by us. NSAI determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued an unqualified audit opinion on our proved reserves at December 31, 2018, based upon their evaluation. NSAI concluded that our estimates of proved reserves were, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI's report, which should be read in its entirety, is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

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Sales Volumes, Price and Cost Data Sales volumes, price and cost data were as follows:

	Sales Volumes [1]			Average Sales Price [1][2]			Production Cost [3]
	Crude Oil & Condensate	NGLs	Natural Gas	Crude Oil & Condensate	NGLs	Natural Gas	Total
	(MBbl)	(MBbl)	(MMcf)	(Per Bbl)	(Per Bbl)	(Per Mcf)	(Per BOE)
Year Ended December 31, 2018							
United States [4]							
DJ Basin	23,165	8,880	83,766	$63.06	$25.32	$ 2.13	$ 4.53
Other US	18,506	13,761	88,370	58.69	26.24	2.90	6.16
Total US	41,671	22,641	172,136	$61.12	$25.88	$ 2.53	$ 5.35
Israel [5]	113	—	86,461	$63.25	$—	$ 5.47	$ 2.30
Equatorial Guinea [6]	5,690	—	77,767	68.53	—	0.27	5.21
Total Consolidated Operations	47,474	22,641	336,364	$62.01	$25.88	$ 2.76	$ 4.78
Equity Investee [7]	576	1,962	—	68.99	42.14	—	—
Total	48,050	24,603	336,364	$62.10	$27.18	$ 2.76	—
Year Ended December 31, 2017							
United States [4]							
DJ Basin	21,564	6,911	70,660	$50.20	$25.22	$ 2.96	$ 4.46
Marcellus Shale	233	1,654	63,443	36.91	23.81	3.15	1.05
Other US	18,757	12,521	87,364	48.01	22.34	2.99	6.48
Total US	40,554	21,086	221,467	$49.11	$23.40	$ 3.02	$ 4.81
Israel							
Tamar Field	130	—	96,894	$46.95	$—	$ 5.37	$ 2.02
Other Israel	—	—	2,346	—	—	3.56	—
Total Israel	130	—	99,240	$46.95	$—	$ 5.32	$ 2.01
Equatorial Guinea [6]	6,460	—	87,269	53.68	—	0.27	4.30
Total Consolidated Operations	47,144	21,086	407,976	$49.73	$23.40	$ 3.01	$ 4.31
Equity Investee [7]	662	2,162	—	55.13	38.48	—	—
Total	47,806	23,248	407,976	$49.84	$24.81	$ 3.01	—
Year Ended December 31, 2016							
United States [4]							
DJ Basin	20,342	7,651	82,431	$40.85	$14.66	$ 2.80	$ 3.99
Marcellus Shale	431	3,094	177,872	28.25	16.34	1.68	0.90
Other US	15,572	9,087	62,017	38.26	14.65	2.42	6.65
Total US	36,345	19,832	322,320	$39.59	$14.92	$ 2.11	$ 3.74
Israel							
Tamar Field	140	—	102,280	$36.67	$—	$ 5.22	$ 2.58
Other Israel	—	—	528	—	—	3.20	—
Total Israel	140	—	102,808	$36.67	$—	$ 5.21	$ 2.60
Equatorial Guinea [6]	9,415	—	85,987	43.54	—	0.27	4.40
Total Consolidated Operations	45,900	19,832	511,115	$40.39	$14.92	$ 2.42	$ 3.72
Equity Investee [7]	629	1,993	—	45.44	26.30	—	—
Total	46,529	21,825	511,115	$40.46	$15.96	$ 2.42	—

(1) The adoption of ASC 606 on January 1, 2018 had a de minimis impact on revenues and production expense for 2018. See Item 8. Financial Statements and Supplementary Data – Note 4. Revenue from Contracts with Customers.

(2) Average realized prices do not include gains or losses on commodity derivative instruments. Item 1A. Risk Factors Item 7A. Quantitative and Qualitative Disclosures About Market Risk Item 8. Financial Statements and Supplementary Data – Note 13. Derivative Instruments and Hedging Activities.

(3) Average production cost includes oil and gas exploration and production operating costs and workover and repair expense and excludes production and ad valorem taxes, gathering, transportation and processing expense, and other royalty expense.

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(4) Amounts include Gulf of Mexico assets prior to the sale in second quarter 2018 and Marcellus Shale assets prior to the sale in second quarter 2017. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.
(5) Sales volume reduction from 2017 is due to the sale of a 7.5% interest in the Tamar field.
(6) See Delivery Commitments – West Africa Agreements.
(7) Volumes represent sales of condensate and liquefied petroleum gas (LPG) from the LPG plant in Equatorial Guinea.

At December 31, 2018, our operated properties accounted for substantially all of our total production. Being the operator of a property improves our ability to directly influence production levels and the timing of projects, while also enhancing our control over operating expenses and capital expenditures.

Productive Wells The number of productive crude oil and natural gas wells in which we held an interest at December 31, 2018 were as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	5,289	4,781	909	842	6,198	5,623
Israel	—	—	7	2	7	2
Equatorial Guinea	5	2	23	8	28	10
Total	5,294	4,783	939	852	6,233	5,635

Productive wells are producing wells and wells mechanically capable of production. A gross well is a well in which a working interest is owned. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. Wells with multiple completions are counted as one well in the table above. Gross crude oil and natural gas wells include 711 wells with multiple completions, meaning completions into more than one productive zone.

Developed and Undeveloped Acreage Developed and undeveloped acreage (including both leases and concessions) in which we held an interest at December 31, 2018 were as follows:

	Developed Acreage		Undeveloped Acreage	
(thousands of acres)	Gross	Net	Gross	Net
United States				
Onshore	549	449	527	384
Offshore	14	5	6	3
Total United States	563	454	533	387
International				
Israel [1]	185	74	284	111
Equatorial Guinea	284	118	81	30
Newfoundland, Canada	—	—	2,332	681
Gabon	—	—	671	403
Cyprus	—	—	95	33
Cameroon	—	—	168	168
Total International	469	192	3,631	1,426
Total	1,032	646	4,164	1,813

(1) Includes 99,000 gross (47,000 net) undeveloped acres for the Alon D license, which we are in the process of relinquishing.

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well. A gross acre is any leased acre in which a working interest is owned. A net acre is comprised of the total of the owned working interest(s) in a gross acre expressed in a fractional format.

The above table includes certain undeveloped acreage that is set to expire if production is not established or we take no other action to extend the terms of the leases, licenses, or concessions within a specified period of time.

Approximately 91,000, 86,000 and 57,000 net undeveloped acres will expire in 2019, 2020, and 2021, respectively. As of December 31, 2018, approximately 20% of our US onshore undeveloped net acres and 25% of our undeveloped net acres in Israel are set to expire in the next three years. As of December 31, 2018, there are no PUDs associated with this acreage.

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Drilling Activity The results of crude oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Net Exploratory Wells			Net Development Wells			
	Productive	Dry	Total	Productive	Dry	Total	Total
Year Ended December 31, 2018							
United States	—	—	—	203.0	—	203.0	203.0
Total	—	—	—	203.0	—	203.0	203.0
Year Ended December 31, 2017							
United States	—	—	—	185.3	—	185.3	185.3
Israel	—	—	—	0.3	—	0.3	0.3
Suriname	—	0.2	0.2	—	—	—	0.2
Total	—	0.2	0.2	185.6	—	185.6	185.8
Year Ended December 31, 2016							
United States	0.4	0.5	0.9	156.7	—	156.7	157.6
Total	0.4	0.5	0.9	156.7	—	156.7	157.6

In addition to the wells drilled and completed in 2018 included in the table above, wells that were in the process of drilling or completing at December 31, 2018 were as follows:

	Exploratory(1)		Development(1)		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	—	—	114.0	107.1	114.0	107.1
Israel (2)	—	—	4.0	1.6	4.0	1.6
Total	—	—	118.0	108.7	118.0	108.7

(1) Amounts exclude wells drilled and suspended awaiting a sanctioned development plan or being evaluated to assess the economic viability of the well.

(2) Includes Leviathan 3, 4, 5 and 7 development wells not yet capable of production. Excludes Tamar Southwest well as it is not in the process of drilling or completing at December 31, 2018.

See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs for additional information on suspended exploratory wells.

Oil and Gas Exploration and Production - Properties and Activities

United States

We have been engaged in crude oil, NGL and natural gas exploration and development activities throughout US onshore since 1932. US operations accounted for 74% of 2018 total consolidated sales volumes and 52% of total proved reserves at December 31, 2018. Approximately 42% of the proved reserves in the US are crude oil and condensate, 32% are natural gas and 26% are NGLs. In second quarter 2018, we exited the Gulf of Mexico through sale of our properties.

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US Onshore

Our US onshore operations are located in proven basins with long-life production profiles. These assets provide low production-risk drilling opportunities in liquids-rich areas that offer predictable and long-term production and cash flow growth at attractive financial returns. In addition, we evaluate and consider other US onshore new venture prospects to complement our portfolio. Locations of our US onshore operations as of December 31, 2018 are shown on the map below:

DJ Basin Our operations in the DJ Basin represent a key asset within our US onshore asset portfolio. As of December 31, 2018, we held approximately 342,000 net acres in the DJ Basin and had proved reserves of 586 MMBoe. Total sales volumes for 2018 were 126 MBoe/d.

2018 Activity In 2018, we focused our drilling and development activity in all three of our main IDP areas, including Mustang, Wells Ranch and East Pony. Our IDP approach has provided an opportunity to efficiently and economically drive production growth by leveraging infrastructure for crude oil, natural gas, and water, including both fresh and produced water assets.

Operationally, our focus on obtaining better results from enhanced completions has led to stronger new well performance. In the Mustang IDP area, our large, contiguous acreage position allows us to focus on row development concepts, which unlike single-pad development, include sequencing operations across a row to more efficiently develop our acreage.

In the Wells Ranch and Mustang IDP areas, we executed acreage trades which add to our contiguous acreage positions and further allow us to control the pace of development and capital investment. During the year, we completed 99 wells and commenced production on 106 wells. We also participated in approximately two non-operated development wells during 2018. As we continue to manage our portfolio, we executed and closed the sale of certain assets in the Greeley Crescent area in 2018 receiving aggregate proceeds of $68 million. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

During 2018, we received approval from Colorado regulators of a Comprehensive Drilling Plan (CDP), the first large-scale CDP approved in the State of Colorado. The CDP spans a 100 square mile position over approximately 64,000 net acres in the Mustang IDP area. With primary operatorship over the acreage, we have the opportunity to control the pace of development and to utilize shared facilities and infrastructure, which is expected to reduce trucking and surface access. As part of the CDP, the permitting process has been clarified and the expiration term for a majority of awarded permits is six years, an increase from the previous two years. We have received permits for over 400 locations across the Mustang IDP area.

Delaware Basin (Permian Basin) Our Delaware Basin position was significantly transformed in 2017 with the closing of the Clayton Williams Energy Acquisition, adding 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings. As of December 31, 2018, we held approximately 108,000 net acres in the Delaware Basin and had proved reserves of 258 MMBoe. Total sales volumes for 2018 were 53 MBoe/d.

2018 Activity In 2018, we continued execution of the Delaware Basin IDP with a focus on lateral length, pad drilling, multi-zone completions and infrastructure development. We transitioned to a row development concept consistent with our strategy in our other US onshore plays. The transition allows for the focusing of development around existing central gathering facilities

(CGFs). In late 2018, we moderated our completion activity in the basin to align with economic and available takeaway capacity.

During the year, we completed 70 wells and commenced production on 72 wells. We also participated in approximately 20 non-operated wells during 2018. In addition, we began flowing production to three newly constructed CGFs, an increase from two CGFs in 2017, operated by Noble Midstream Partners.

We utilize the Advantage Pipeline (defined below), which is 50% owned by Noble Midstream Partners, for a portion of our crude oil takeaway. Additionally, we have supplemented our Delaware Basin takeaway position with a firm sales agreement which brings our crude oil to the Texas Gulf Coast. The five-year agreement provides for firm gross sales of at least 10 MBbl/d of crude oil beginning in July 2018, which increased to 20 MBbl/d beginning in October 2018 and for the remainder of the agreement. Currently, crude oil sold under the agreement utilizes the buyer's existing firm transport capacity to Corpus Christi, Texas. Once the EPIC Crude Oil Pipeline is fully in service, we will utilize our own firm transport on the EPIC pipeline, discussed below, to deliver volumes to the buyer in Corpus Christi, Texas. We also have a firm sales agreement for gross crude oil volumes of 5 MBbl/d for 2019.

Also during 2018, we dedicated substantially all of our Delaware Basin acreage position in Reeves County, Texas to the EPIC Crude Oil Pipeline for firm transport of up to 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. EPIC announced that it will provide early access to oil pipeline transportation through its Y-Grade Pipeline in third quarter 2019 while the EPIC Crude Oil Pipeline construction continues with in-service expected in first quarter 2020. This strategic agreement is expected to provide long-term flow assurance for our growing crude oil volumes in this area. 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, in first quarter 2019, we assigned Noble Midstream Partners our option to acquire a 30% equity interest in the EPIC Crude Oil Pipeline, and Noble Midstream Partners subsequently exercised this option with EPIC. Closing of Noble Midstream Partners' equity interest in the EPIC Crude Oil Pipeline is anticipated in first quarter 2019 and subject to certain conditions precedent. Concurrently, Noble Midstream Partners exercised and closed its option with EPIC to acquire a 15% equity interest in the EPIC Y-Grade pipeline. Cash consideration is expected to total approximately $330 million to $350 million for the interest in the EPIC Crude Oil Pipeline and approximately $165 million to $180 million for the interest in the EPIC Y-Grade Pipeline. Noble Midstream Partners intends to fund the equity investments with its revolving credit facility and/or additional sources of funding. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Eagle Ford Shale As of December 31, 2018, we held approximately 35,000 net acres located in Webb and Dimmit counties and had proved reserves of 158 MMBoe. Total sales volumes for 2018 were 69 MBoe/d. Since acquiring these assets, we have continued to apply IDP learnings and enhancements to optimize development of these assets, including optimizing drilling and completion designs to increase investment efficiency. We have also focused on testing co-development of both the Upper and Lower Eagle Ford formation zones.

2018 Activity Our 2018 capital program was primarily focused within the Upper and Lower Eagle Ford formation zones where we completed 20 wells and commenced production on 13 wells. All wells drilled during 2018 were on multi-well pads leveraging centralized infrastructure. In addition, we continued construction of a central delivery facility in the northern area of Gates Ranch which will provide separation and compression capabilities for our multi-well completion program which began in fourth quarter 2018 and will continue into 2019.

Onshore Exploration Activity In 2018, we captured over 100,000 net acres through undeveloped leasehold acquisition activity in the US onshore. In 2019, we expect to perform additional geologic studies and conduct permitting activities.

US Offshore

In second quarter 2018, we closed the sale of our Gulf of Mexico assets, receiving net proceeds of $384 million and recorded a loss on sale of $24 million. Average annual sales volumes for 2018 were 7 MBoe/d. Proved reserves associated with these properties totaled 23 MMBoe. The divestment enables us to further focus our organization on our highest-return areas that are expected to deliver production and cash flow growth.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Liquidity and Capital Resources and Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

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International

Our international business focuses on offshore opportunities in a number of countries and diversifies our portfolio. Development projects in the Eastern Mediterranean and West Africa have contributed substantially to our production and cash flow growth over the last decade. Previous exploration successes in these areas have also identified multiple major development projects that have the potential to contribute to long-term production and cash flow growth in the future.

During 2018, we progressed development of offshore Israel assets primarily through the continued development of Leviathan, where first natural gas sales are anticipated by the end of 2019. In addition, we advanced our Eastern Mediterranean regional natural gas export opportunities by executing natural gas sales and purchase agreements (GSPAs) for the Leviathan and Tamar fields, offshore Israel, and continue efforts to monetize our significant natural gas discoveries offshore West Africa.

Operations in Equatorial Guinea, Cameroon, Gabon, and Cyprus are conducted in accordance with the terms of Production Sharing Contracts (PSCs). Operations in Israel, Newfoundland (Canada) and other foreign locations are conducted in accordance with concession agreements, permits or licenses. See Item 1A. Risk Factors.

Eastern Mediterranean (Israel and Cyprus) One of our operating areas is the Eastern Mediterranean, where we have identified the existence of substantial natural gas resources since we obtained our first exploration license in 1998.

Israel, our only producing country in our Eastern Mediterranean area, contributed an average of 239 MMcfe/d, net, of natural gas sales volumes in 2018, representing approximately 12% of total consolidated sales volumes, primarily from the Tamar field. As of December 31, 2018, we had 830 MMBoe of proved reserves in Israel, which represents approximately 43% of total proved reserves. Reserves include proved undeveloped reserves associated with the Leviathan field development. Our leasehold position in the Eastern Mediterranean at December 31, 2018, included six leases and one license operated offshore Israel. In offshore Cyprus, we operate under the terms of a PSC.

At December 31, 2018, the Eastern Mediterranean position included approximately 74,000 net developed acres and 111,000 net undeveloped acres located between 10 and 90 miles offshore Israel in water depths ranging from 700 feet to 6,500 feet. Approximately 47,000 of the 111,000 net undeveloped acres relate to the Alon D license, which we are in the process of relinquishing. The license offshore Cyprus covers approximately 33,000 net undeveloped acres adjacent to our offshore Israel acreage.

Locations of our operations in the Eastern Mediterranean as of December 31, 2018 are shown below:

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Offshore Israel Noble Energy and our partners have delivered reliable and affordable natural gas to Israeli customers for over a decade. During this time, we have delivered approximately 2.65 Tcf, gross, of natural gas to Israeli customers, including the Israel Electric Corporation (IEC), the largest supplier of electricity in the country.

We are the first company to construct, operate and produce from a major energy development project offshore Israel. Our Mari-B discovery provided the country with its first supply of domestic natural gas in 2004. In 2009, we discovered the Tamar field, another substantial natural gas resource. To maintain and increase natural gas supply to Israel, we developed the Tamar field with a discovery to production cycle time of approximately four years, which is exceptionally fast by global industry standards for an offshore natural gas project of this magnitude and complexity.

In 2010, we discovered the Leviathan field, our largest natural gas discovery to date. The quantity of discovered natural gas resources at Tamar and Leviathan positions Israel to meet domestic needs for decades and to become a significant natural gas exporter. Multiple natural gas customers exist in the region, and Israel's domestic demand is predicted to continue to grow over the next decade, primarily driven by increased use of natural gas over coal to fuel electric power generation. During 2018, increased demand for electricity, continued coal displacement and almost 100% asset uptime, enabled us to set a new Tamar cumulative sales volume record of 1.75 Tcf gross. As customer demand increases and to reinforce the reliability of the Tamar project, we have continued to progress regulatory approval with the Government of Israel regarding the development plan for our 2013 Tamar Southwest discovery.

In addition to our natural gas discoveries, the Levant Basin is prospective for crude oil at greater depths. We conducted preliminary exploration activities in 2012 and, in 2018, continued analysis of potential for future exploration. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Domestic Natural Gas Demand As the Israeli economy continues to grow, the demand for natural gas used primarily for electricity generation is also expected to grow. Demand for natural gas in the industrial sector, including refineries, chemical, desalination, cement and other plants, as well as residential uses, is also increasing. These sectors are gaining confidence that a long-term supply of affordable natural gas will be available and are now investing the capital necessary to convert facilities and infrastructure to use natural gas. In addition, government requirements for emissions reductions have also driven incremental demand for natural gas beginning in 2016. We have executed numerous GSPAs with domestic customers. See Delivery Commitments – Israel Agreements.

Regional Natural Gas Demand and Exports The Eastern Mediterranean presents an opportunity to match our affordable, abundant supply of natural gas with a substantially undersupplied regional market, including customers in Jordan and Egypt. With the Tamar field online providing reliable production, and the development of the Leviathan field progressing, we are well positioned to supply natural gas to the region for many years. In first quarter 2018, we announced the execution of certain agreements to supply natural gas from the Leviathan and Tamar fields to customers in Egypt. See *GSPAs and Transportation Agreements for Israeli Export*, below.

Tamar Natural Gas Project (25% operated working interest) The Tamar project began production in March 2013 and has peak flow rates of approximately 1.1 Bcf/d, gross. In 2015, we completed the Tamar compression project, which expanded field production capacity by adding compression at the Ashdod onshore terminal (AOT). In 2017, we installed subsea equipment to connect the Tamar 8 development well to the Tamar subsea system. Additionally, in 2017 we completed and commenced production from the Tamar 8 development well, which increases supply reliability as domestic demand for natural gas continues to grow.

In January 2019, the Petroleum Commissioner approved the development plan associated with our 2013 Tamar Southwest discovery, which includes the drilling of an additional development well to reinforce the reliability for the Tamar project and support increased customer demand.

We are also assessing the possibility for expansion of the Tamar project. The project could expand field deliverability from the current capacity level of approximately 1.2 Bcf/d up to approximately 2.1 Bcf/d, a quantity that could allow for additional regional export. Expansion options could include additional investments in pipelines, wells and platform upgrades. Timing of project sanction is dependent upon progress relating to domestic and regional marketing efforts of these resources as well as regulatory approvals from respective governments and capital allocation management.

The Israel Natural Gas Framework (Framework) provided for the reduction in our ownership interest in the Tamar field from 36% to 25% by year-end 2021. We completed the sell-down through a series of transactions, whereby we divested 3.5% of our interest in 2016, and in March 2018, we closed the sale of a 7.5% working interest in Tamar field to Tamar Petroleum Ltd (TASE: TMRP). Proved reserves related to the 7.5% interest sold total 502 Bcf, or approximately 84 MMBoe. In 2018, we also subsequently sold our investment in TMRP shares. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

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Leviathan Natural Gas Project (39.66% operated working interest) In early 2017, we announced project sanction of phase 1 of the Leviathan natural gas project and recorded initial proved reserves of 3.3 Tcf (551 MMBoe) associated with the first phase of development. The first phase of development of the Leviathan field provides 1.2 Bcf/d of production capacity and consists of four wells, a subsea production system and a shallow-water processing platform, with a connection to an onshore valve station and the Israel Natural Gas Lines (INGL) pipeline network.

We expect our share of development costs to total approximately $1.5 billion and remaining costs will be funded from our share of cash flows from the Tamar asset. As we progress through the initial phase of development, we have included volume capacity expansion optionality on the Leviathan platform to allow for cost effective expansion to meet growing regional natural gas demand.

As of December 31, 2018, the project is approximately 75% complete and remains on budget and on schedule. During 2018, we installed the in-field gathering and export pipelines, completed installation of all subsea trees, finished completions on all four wells with successful flowbacks, completed the float of the main decks and jacket rollup, flowline installation and completed jacket fabrication and sail-away. Project start up is anticipated by the end of 2019.

We are actively engaged in natural gas marketing activities to fill Leviathan Phase 1 capacity and have progressed multiple GSPAs with initial contracted quantities during 2020-2022 of up to approximately 922 MMcf/d, gross (approximately 320 MMcf/d, net) as of December 31, 2018 to supply customers in Israel, Jordan and Egypt.

GSPAs and Transportation Agreements for Israeli Export We have entered into a GSPA for the sale of 1.6 Tcf, gross (555 Bcf, net), of natural gas from the Leviathan field to the National Electric Power Company Ltd. (NEPCO) of Jordan, with pricing terms indexed to Brent crude oil. The agreement provides for sales of natural gas intended for consumption in power production facilities over a 15-year period. Sales to NEPCO are anticipated to commence at field startup.

In first quarter 2018, we executed two independent GSPAs for the sale of 2.3 Tcf, gross (651 Bcf, net), of natural gas from the Leviathan and Tamar fields to Dolphinus Holdings Limited to supply natural gas in Egypt. Sales volumes under the GSPA associated with the Leviathan field are anticipated to begin at a firm rate of approximately 350 MMcf/d, gross (approximately 121 MMcf/d, net), at the startup of the Leviathan project. For the Tamar agreement, sales volumes are anticipated to begin at an interruptible rate of up to 350 MMcf/d, gross (approximately 77 MMcf/d, net), dependent upon gas availability beyond existing customer obligations in Israel and Jordan. The GSPA includes an option to convert the Tamar interruptible quantity to a firm-basis with a take or pay commitment. Both contracts are for a 10-year term and have pricing terms indexed to Brent crude oil, similar to other export contracts in the region. The GSPAs are subject to satisfaction of conditions precedent, including regulatory approvals and licenses, and finalizing natural gas transportation agreements.

In September 2018, we announced the execution, along with certain third-parties, of agreements to support delivery of natural gas into Egypt. With certain partners, we plan to acquire a 39% equity interest in Eastern Mediterranean Gas Company S.A.E., which owns the EMG Pipeline. We will own an effective, indirect interest of approximately 10% net in the pipeline and, along with our partners, will enter into an agreement to exclusively operate the pipeline, securing access to the pipeline's full capacity. Closing of the agreement is subject to fulfillment of certain conditions precedent, which is expected in the first half of 2019, and our portion of estimated acquisition costs is approximately $200 million, net. Technical evaluation and flow reversal activities are currently underway.

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

Alon D License In August 2017, the Petroleum Commissioner of Israel granted us a 32-month extension of the Alon D license *(47.059% operated working interest)* to drill an exploration well. As of December 31, 2018, we are in the process of relinquishing the license.

Dalit Discovery Our development plan for the Dalit field *(25% operated working interest)*, a 2009 natural gas discovery, was approved by the Government of Israel. Development includes a tieback to the Tamar platform. We are also analyzing 3D seismic data to evaluate the additional potential of the area, including the possible existence of hydrocarbons at deeper intervals.

Israel Natural Gas Framework and Regulatory Environment We are subject to certain fiscal, antitrust and other regulatory challenges in Israel. These challenges have been addressed with the enactment of the Framework by the Government of Israel. See Regulations – Israel Regulatory Environment and Item 1A. Risk Factors – *Our Eastern Mediterranean discoveries bear certain technical, geopolitical, regulatory, and financial challenges that could adversely impact our ability to monetize these natural gas assets*.

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

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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.

West Africa (Equatorial Guinea, Cameroon and Gabon) West Africa includes the Alba field, Block O and Block I offshore Equatorial Guinea, the YoYo PSC, offshore Cameroon, and one block offshore Gabon. In West Africa, our interests can be burdened by overriding royalty interests and/or other government interests. As such, our working interests may differ from our revenue interests. Equatorial Guinea is currently the only producing country in our West Africa segment and, excluding the impact of equity investees, Equatorial Guinea contributed an average of 51 MBoe/d of sales volumes in 2018 and represented approximately 15% of total consolidated sales volumes. At December 31, 2018, Equatorial Guinea had proved reserves of 97 MMBoe, which represents approximately 5% of total proved reserves. No wells were completed or participated in during the year.

Locations of our upstream operations in West Africa, as of December 31, 2018 are shown on the map below:

Aseng Field Aseng is an oil field on Block I *(40% operated working interest, 38% revenue interest)*, offshore Equatorial Guinea, which began producing in 2011. The development includes five horizontal producing wells flowing to the Aseng floating production, storage and offloading vessel (FPSO) where the crude oil is stored until sold, and natural gas and water are reinjected into the reservoir to maintain pressure and maximize crude oil recoveries. During 2018, sales volumes from the Aseng field averaged 6 MBbl/d, net.

The Aseng FPSO is designed to act as a crude oil production hub, as well as a liquids storage and offloading facility, with capabilities to support future subsea oil field developments in the area. It also has the ability to process and store condensate from natural gas condensate fields in the area, the first of which is Alen. Since it first came online, the Aseng field has maintained reliable performance, averaging almost 100% production uptime and, as of December 31, 2018, has produced over 95 MMBbls of cumulative gross crude oil production.

In late 2018, we submitted a plan of development to the Government of Equatorial Guinea for the drilling of an additional crude oil development well. The well would be tied into existing subsea infrastructure and is expected to add crude oil reserves, minimize field declines and extend the reservoir life of the Aseng field. We expect to sanction the project in the near future with first oil anticipated in late 2019.

Alen Field Alen is a natural gas and condensate field primarily on Block O *(51% operated working interest, 45% revenue interest)*, offshore Equatorial Guinea, which includes three production wells and three natural gas injection wells connected to a production platform. Condensate is pumped to the Aseng FPSO for storage and offloading. Alen has been producing since 2013 and sales volumes averaged approximately 2 MBbl/d, net, during 2018. As of December 31, 2018, Alen has produced over 36 MMBbls of cumulative gross condensate production. The Alen platform is expected to be utilized in our natural gas monetization efforts. See *West Africa Natural Gas Monetization*, below.

Alba Field Alba is a natural gas and condensate field located offshore Equatorial Guinea *(33% non-operated working interest, 32% revenue interest)*, which has been producing since 1991. Operations include the Alba field and related production and condensate storage facilities, a LPG processing plant where additional condensate is extracted along with LPGs, and a methanol plant capable of producing up to 3,100 gross metric tons per day of methanol. The LPG processing plant and the methanol plant are located on Bioko Island, Equatorial Guinea. During 2018, Alba field sales volumes averaged 50 MBoe/d, net, reflecting 43 MBoe/d attributable to total sales volumes and 7 MBoe/d attributable to an equity investee.

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We sell our share of primary condensate produced in the Alba field under short-term contracts at market-based prices. We sell our share of natural gas production from the Alba field to the LPG plant, the methanol plant, an unaffiliated liquefied natural gas (LNG) plant and a power generation plant. The LPG plant is owned by Alba Plant LLC (Alba Plant), in which we have a 28% interest. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest. AMPCO purchases natural gas from the Alba field under a contract that runs through 2026 and subsequently markets the produced methanol primarily to customers in the US and Europe. Alba Plant sells its LPG products and secondary condensate at our marine terminal at prevailing market prices.

We account for both Alba Plant and AMPCO as equity method investments and present our share of income as a component of revenues. See Item 8. Financial Statements and Supplementary Data – Note 15. Equity Method Investments.

West Africa Natural Gas Monetization We continue efforts to monetize our significant natural gas discoveries offshore West Africa (YoYo, Yolanda and Felicita).

A natural gas development team has been working with local governments to evaluate natural gas monetization development plans 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 and Equatorial Guinea LNG Holdings Limited's LNG plant. Both plants are located in Punta Europa. The contemplated structure would result in Alen natural gas being marketed to global LNG customers. Sanction of the project is contingent upon final commercial agreements being executed.

Existing production and processing facilities in place at the Alen platform and in Punta Europa require certain modifications to produce and process the Alen natural gas. The agreement contemplates construction of a 65-kilometer pipeline to transport natural gas from the Alen platform to the facilities in Punta Europa. We have awarded front-end engineering design (FEED) activities to progress the project to final investment decision, which is planned for 2019 with first gas anticipated in 2021.

Offshore Cameroon We have an interest in the YoYo PSC *(100% operated working interest)*. The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options, which will provide a more robust framework directly related to oil and gas operational activities.

Offshore Gabon We are the operator of Block Doukou Dak *(60% working interest)*, an undeveloped, deepwater area. Our exploration commitment includes an obligation for 3D seismic, which was acquired and processed throughout 2016 and the first half of 2017. We received the final product mid-year 2017 and are currently evaluating the seismic data results.

See also Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Other International Other international operations include the following:

Offshore Newfoundland (Canada) We have a non-operated 25% working interest in exploration licenses (EL) EL1145, EL 1146 and EL 1148, and a non-operated 40% working interest in EL 1149. BP Canada Energy Group ULC is the operator of the blocks. We licensed 3D seismic data to help us assess the economic viability of numerous exploration leads and prospects.

Offshore Suriname In October 2017, our partner spud the Araku-1 exploration well in Block 54 offshore in the Atlantic Ocean and subsequently plugged and abandoned the well. As a result, we recorded dry hole expense of $7 million in 2017. Based upon well results, modeling of the basin and review of further prospectivity, we released our non-operated 20% working interest and no longer have acreage offshore Suriname as of December 31, 2018.

Offshore Falkland Islands In 2016, following completion of our geological assessment, we exited all licenses, excluding the PL-001, which contained the Rhea prospect, and recorded $25 million of undeveloped leasehold impairment expense. In fourth quarter 2018, we provided notice to the Falklands government and exited our remaining license. As of December 31, 2018, we no longer have acreage offshore Falkland Islands.

North Sea The non-operated MacCulloch field is currently undergoing decommissioning activities. Due to its size and location, field abandonment is a multi-year process, requiring several phases. Therefore, our share of estimated field abandonment costs, recorded as an asset retirement obligation (ARO), may change over time.

Midstream – Properties and Activities

We continue to develop our Midstream segment, which includes gathering, treating, and transportation assets, as well as water-related infrastructure, including fresh water delivery and produced water disposal assets. Our Midstream assets are strategically located with our development and production activities in the DJ and Delaware Basins and provide services to us and other third-party customers.

Noble Midstream Partners Our Midstream operations include those of Noble Midstream Partners, a publicly traded, consolidated subsidiary and limited partnership that constructs and operates a wide range of domestic midstream infrastructure

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assets. Noble Midstream Partners is a fee-based, growth-oriented Delaware master limited partnership formed in December 2014 organized in a development company structure. On September 20, 2016, Noble Midstream Partners completed its initial public offering of common units, which provided Noble Midstream Partners access to the capital markets to support funding of its US onshore midstream investment program. At December 31, 2018, our ownership interest in Noble Midstream Partners consisted of a 45.4% limited partner interest, the entire non-economic general partner interest, and all incentive distribution rights.

In addition to developing and operating midstream assets, Noble Midstream Partners leveraged its existing dedications and commercial relationships through investing in certain partnerships providing transportation services downstream of our current operations. As of December 31, 2018, Noble Midstream Partners has a 50% interest in Advantage Pipeline L.L.C. (Advantage Pipeline) in the Delaware Basin and a 3.33% interest in White Cliffs Pipeline L.L.C. (White Cliffs) in the DJ Basin. In first quarter 2019, we assigned Noble Midstream Partners our option to acquire a 30% equity interest in the EPIC Crude Oil Pipeline, and Noble Midstream Partners subsequently exercised this option with EPIC. Closing of Noble Midstream Partners' equity interest in the EPIC Crude Oil Pipeline is anticipated in first quarter 2019 and subject to certain conditions precedent. Concurrently, Noble Midstream Partners exercised and closed its option with EPIC to acquire a 15% equity interest in the EPIC Y-Grade Pipeline. Cash consideration is expected to total approximately $330 million to $350 million for the interest in the EPIC Crude Oil Pipeline and approximately $165 million to $180 million for the interest in the EPIC Y-Grade Pipeline. Noble Midstream Partners intends to fund the equity investments with its revolving credit facility and/or additional sources of funding. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

The following diagram depicts our organizational structure as of December 31, 2018. Development companies identified in red and blue indicate the location of the assets as either in the DJ or Delaware Basin, respectively.

Major Construction Projects Activity in 2018 primarily focused on construction and development of midstream infrastructure assets, including:

- completed construction of the Collier, Billy Miner Train II and Coronado CGFs in the Delaware Basin;
- completed construction of freshwater delivery infrastructure and commenced gathering services in the DJ Basin; and
- signed a non-binding letter of intent with Salt Creek Midstream LLC (Salt Creek) for construction of a crude oil pipeline system in the Delaware Basin, for which definitive agreements with Salt Creek were executed in February 2019.

In 2019, we expect our midstream investment to continue to focus on the DJ and Delaware Basins to meet the needs of our upstream operations and third-party customers.

Noble Midstream Partners Saddle Butte Acquisition On January 31, 2018, Noble Midstream Partners acquired a 54.4% interest in 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), which completed the acquisition of Saddle Butte from Saddle Butte Pipeline II, LLC (Saddle Butte Acquisition). Saddle Butte owned a large-scale integrated gathering system, located in the DJ Basin, which we subsequently renamed the Black Diamond gathering system. In addition to gathering services, certain oil purchases and sales occur within this business to better leverage existing infrastructure as well as to provide additional flexibility to Black Diamond's customer base. Cash consideration totaled $681 million, approximately $343 million of which was funded by Greenfield. Noble Midstream Partners operates the Black Diamond gathering system and we consolidate the entity for financial reporting purposes. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Other Noble Energy Midstream Assets Outside of Noble Midstream Partners and our interests in its development companies, we have retained full ownership in certain midstream businesses. Primarily, we own and operate two natural gas processing plants in the DJ Basin, crude oil gathering assets in the DJ and Delaware Basins, fresh water delivery assets in the Delaware Basin and gathering assets in the Eagle Ford Shale. We have granted rights of first refusal (ROFRs) on a combination of midstream assets retained by us outside of Noble Midstream Partners to provide midstream services on certain acreage and/or to acquire certain midstream assets.

Marcellus Shale CONE Gathering Divestiture In January 2018, we completed the sale of our 50% interest in CONE Gathering LLC (CONE Gathering) to CNX Resources Corporation and received proceeds of $309 million. After the sale, we held 21.7 million common units, representing a 34.1% limited partner interest, in CNX Midstream Partners LP (CNX Midstream Partners, NYSE: CNXM). We sold these units in 2018 receiving net proceeds of $387 million. The investment was previously accounted for under the equity method of accounting. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Third-Party Customers During 2018, Noble Midstream Partners continued providing crude oil and produced water gathering and fresh water delivery services to unaffiliated third parties in the Greeley Crescent IDP area of the DJ Basin. Additionally, the acquisition of interest in the Saddle Butte system has significantly increased the number of third-party customers across our Midstream segment.

Delivery Commitments

US Onshore Agreements Crude oil, NGLs, natural gas and condensate produced in the US onshore are sold under varying contracts, including short-term, long-term or life-of-field contracts where all production from a well or group of wells is sold to one or more customers, at market-based prices adjusted for location and quality. Certain of our sales and delivery agreements may include natural gas processing or NGL fractionation commitments for the volumes delivered, either to a customer or to a service provider as assessed and accounted for under ASC 606.

In addition, we have certain sales and delivery agreements to supply minimum quantities of production to various customers. The majority of our production is sold under short-term contracts. At December 31, 2018, long-term (greater than one year) sales commitments we were contractually committed to deliver included our five-year agreement which brings a portion of our Delaware Basin crude oil to the Texas Gulf Coast. Remaining quantities to be delivered under this agreement are 36.5 MMBbls. We expect to fulfill this delivery commitment with existing proved developed and proved undeveloped reserves, which we regularly monitor to ensure sufficient availability to meet the commitments.

Israel Agreements We currently sell natural gas from the Tamar field primarily to the IEC and numerous other Israeli purchasers, including independent power producers, cogeneration facilities and industrial companies. Most contracts provide for the sale of natural gas over an initial term of one to 18 years. Some of the contracts provide f

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ximately 4.5 Tcf, gross (1.0 Tcf, net), of natural gas remained to be delivered under our Tamar contracts. As of December 31, 2018, we have recorded 1.5 Tcf, net, of proved na

ves of 1.3 Tcf, net, and PUD r s of 241 Bcf, net, for the Tamar field. Based on current production levels and future development plans, our available quantities of prove

ements without further capital investment. In addition, we have also executed certain interruptible GSPAs which would supply natural gas from Tamar.

We have also executed firm natural gas sales agreements for the sale of approximately 2.2 Tcf, gross (0.8 Tcf, net) of natural gas from the Leviathan field to customers in Israel and Jordan. Sales are anticipated to begin at the startup of the Leviathan project, currently projected for the end of 2019. As of December 31, 2018, we have recorded 3.3 Tcf, net, of PUD reserves for the Leviathan field related to sales to Israeli and Jordanian customers. See Eastern Mediterranean (Israel and Cyprus) - GSPAs and Transportation Agreements for Israeli Export.

West Africa Agreements 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) and are transported via tankers.

Natural gas from the Alba field is sold for $0.25 per MMBtu to a methanol plant, an LPG plant, an unaffiliated LNG plant and a power generation plant. The sales contract with the methanol plant runs through 2026, and the sales contract with the LNG plant runs through 2023. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method.

See Item 8. Financial Statements and Supplementary Data – Note 4. Revenue from Contracts with Customers.

BP North American Funding (BP) and Shell Trading (US) (Shell) were the largest single purchasers of our 2018 production. See Item 8. Financial Statements and Supplementary Data – Note 3. Segment Information.

Transportation Commitments

firm transportation contracts for some of our US onshore production. We use long-term contracts such as these to provide production flow assurance and ensure access to markets for our products at the best possible price and at the lowest possible logistics cost

Our financial commitments under these contracts are included in our contractual obligations disclosures. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Contractual Obligations, Item 8. Financial Statements and Supplementary Data – Note 10. Marcellus Shale Firm Transportation Commitments and – Note 11. Commitments and Contingencies.

Regulations

Exploration for, and development, production and marketing of, crude oil, NGLs and natural gas are extensively regulated at the federal, state, and local levels in the US, and internationally. Regulations affecting the crude oil and natural gas industry are under constant review for amendment or expansion over time and frequently impose more stringent requirements on crude oil and natural gas companies.

Various governmental bodies have issued rules, regulations and orders that require extensive efforts to ensure compliance, that impose incremental costs to comply, and that carry substantial penalties for failure to comply, which may impact our ability to economically produce and sell crude oil, NGLs and natural gas. These issuances may restrict the rate of crude oil, NGL and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory requirements on the crude oil and natural gas industry often result in incremental costs of doing business and consequently affect our profitability. See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental requirements that may restrict our access to land*

and/or cause us to incur substantial incremental costs.

Various domestic and international agencies have legal and regulatory authority and oversight over our exploration for, and production and sale of, crude oil, NGLs and natural gas. Internationally, oversight also includes energy-related ministries or other agencies of our host countries, each having certain relevant energy or hydrocarbons laws. Other US federal agencies with certain authority over our business include the Internal Revenue Service (IRS) and the SEC. In addition, we are governed by the rules and regulations of the NYSE, upon which shares of our common stock and common units of Noble Midstream Partners are traded.

Among the laws affecting our operations are the following:
Environmental Matters We take into account the cost of complying with environmental regulations in planning, designing, drilling, operating, and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production wastes, water and air pollution control procedures, facility siting and construction, protection of endangered species and habitat, prevention of and responses to leaks and spills, and the remediation of petroleum-product contamination. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, habitat to endangered or threatened species, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations. Where our drilling activities could result in a serious adverse effect upon a protected species, a federal or state agency could order a complete halt to such activities in certain locations or during certain seasons. Consequently, the presence of a protected species in areas where we operate could adversely affect future production from those areas and government agencies frequently add to the lists of protected species.

Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us, or by prior owners or operators, in accordance with current laws, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups. The US Environmental Protection Agency (EPA) and various state agencies have limited the disposal options for hazardous and non-hazardous wastes and may continue to do so. The owner and operator of a site, and persons that treated, disposed of, or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The EPA, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from the definition of hazardous waste may in the future be subject to considerably more rigorous and costly operating and disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary.

Under federal and state occupational safety and health laws, we must develop and maintain information about hazardous materials used, released, or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities, and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards. Moreover, certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

We have made and will continue to make expenditures necessary to comply with environmental requirements. We do not believe that compliance with such requirements will have a material adverse effect on our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact on the crude oil and natural gas industry, they do not appear to affect us to any greater or lesser extent than other companies in the industry.

Apart from these federal matters, most of the states where we operate have separate authority to regulate operational and environmental matters.

Colorado The oil and gas industry is regulated in part by the Colorado Oil and Gas Conservation Commission (COGCC). In December 2018, the COGCC approved an increased setback distance for crude oil and natural gas wells and production facilities located in close proximity to schools based on an expanded definition of "school facility." Previously, the COGCC had allowed uniform setback distances of 500 feet from occupied buildings and 1,000 feet from high occupancy building units. The setback rules also require operators to utilize increased mitigation measures to limit potential drilling impacts and require advance notice to surface owners, owners of occupied building units, and local governments prior to the filing of an Application for Permit to Drill or Oil and Gas Location Assessment. The COGCC also has implemented rules making Colorado the first state to require sampling of groundwater for hydrocarbons and other indicator compounds both before and after drilling. Further, the COGCC has adopted rules increasing the maximum penalty for violations of its requirements.

The state environmental agency, the Colorado Department of Public Health and Environment (CDPHE), likewise has adopted measures to regulate air emissions, water protection, and waste handling and disposal relating to our crude oil and natural gas exploration and production. For air, the CDPHE has extended the EPA's emissions standards for crude oil and natural gas operations to directly control methane.

In the state of Colorado, we have historically encountered initiatives to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations. For example, in November 2018, a majority of Colorado voters voted against Proposition #112, which, if passed, would have significantly limited, or in some cases prevented, the future development of crude oil and natural gas and demand for our midstream services in areas where we currently conduct operations. If similar regulatory measures are adopted, we could incur additional costs to comply with any of its requirements or may experience delays and/or curtailment in the permitting or pursuit of our exploration, development, or production activities. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our cash flows, results of operations, financial condition, and liquidity.

It is likely these types of initiatives will continue into the future in Colorado, and efforts by the US Administration to modify federal oil and gas related regulations could intensify the risk of anti-development efforts from grass roots opposition. See Item 1A. Risk Factors – *We face various risks associated with the trend toward increased anti-oil and gas development activity.*

Some of the counties and municipalities where we operate in Colorado have adopted their own regulations or ordinances that impose additional restrictions on our crude oil and natural gas exploration and production. To date these have not significantly impacted our operations.

In April 2015, we entered into a joint consent decree (Consent Decree) with the EPA, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream crude oil and natural gas operations within the Non-Attainment Area of the DJ Basin. All fines required under the Consent Decree were paid in 2015; however, the required injunctive relief remains ongoing. We have concluded that the penalties, injunctive relief, plugging and abandonment activities, and mitigation expenditures that result from this settlement, based on currently available information, will not have a material adverse effect on our financial position, results of operations or cash flows. See Item 1A. Risk Factors – *Our operations require us to comply with a number of US and international laws and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business* and Item 8. Financial Statements and Supplementary Data – Note 11. Commitments and Contingencies.

Texas Texas has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells.

The oil and gas industry is regulated in part by the Texas Railroad Commission (RRC). The RRC requires Texas oil and gas operators to disclose on the FracFocus website chemical ingredients and water volumes used in hydraulic fracturing treatments. FracFocus.org is a public registry operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council.

In addition, the RRC maintains a "well integrity rule" that addresses requirements for drilling, casing and cementing wells. The rule also includes testing and reporting requirements, including clarifying that cementing reports must be submitted after well completion or after cessation of drilling, whichever is earlier. Furthermore, the RRC oversees permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. The RRC has used this authority to deny permits for waste disposal wells.

Climate Change In recent years, the EPA has finalized a series of greenhouse gas (GHG) monitoring, reporting and emissions control rules for the oil and natural gas industry, and the US Congress has, from time to time, considered adopting legislation to reduce emissions. In addition, almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs.

At the international level, in December 2015, the US signed the Paris Agreement on climate change and pledged to take efforts to reduce GHG emissions and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement entered into force in November 2016. However, in August 2017, the US notified the United Nations that it would be withdrawing from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the US. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. While the US Administration expressed a clear intent to cease implementing the Paris Agreement, it is not clear how it plans to accomplish this goal, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

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The current state of development of the ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties, legislation or new regulations. However, future restrictions on emissions of GHGs, or related measures to encourage use of renewable energy could have a significant impact on our future operations and reduce demand for our products. See also Item 1A. Risk Factors.

Israel Regulatory Environment The Framework, as adopted by the Government of Israel, provides clarity on numerous matters concerning resource development, including certain fiscal, antitrust and other regulatory matters. The Framework provided for the reduction of our ownership interest in the Tamar and Dalit fields to 25% by year-end 2021, which we completed in 2018, while enabling the marketing of Leviathan natural gas to Israeli customers. See Item Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Hydraulic Fracturing

Hydraulic fracturing techniques have been used for decades on the majority of all new onshore crude oil and natural gas wells drilled domestically. The process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate oil and gas production. We strive to adopt best practices and industry standards and comply with all regulatory requirements regarding well construction and operation. For example, the qualified service companies we use to perform hydraulic fracturing, as well as our personnel, monitor rate and pressure to assure that the services are performed as planned. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into those aquifers. To help reduce our operational demand for freshwater and need for disposal, we are currently developing technology and infrastructure to expand our water recycling capacity in the DJ and Delaware Basins. We believe that these processes help ensure hydraulic fracturing is safe and does not and will not pose a risk to water supplies, the environment or public health.

All of the states where our US onshore operations are located (including Colorado and Texas) have developed hydraulic fracturing regulations. See Regulations - Colorado and Texas. Although hydraulic fracturing is regulated primarily at the state level, both Congress and government agencies at all levels from federal to municipal are studying the potential impacts of hydraulic fracturing, and some agencies have asserted regulatory authority over hydraulic fracturing and/or certain aspects of oil and gas operations connected with the hydraulic fracturing process. Some agencies have implemented new requirements, and some are evaluating the need for additional requirements. For example:

- legislation has been proposed in Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process;
- the Bureau of Land Management (BLM), as a result of legal challenges, has published a final rule to rescind its 2015 rule governing hydraulic fracturing on federal and Indian lands. Further legal challenges are expected;
- the Occupational Safety and Health Administration (OSHA) has lowered exposure limits for workers who use silica (sand) in hydraulic fracturing activities, and silica work practices have become stricter;
- state and federal regulatory agencies have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity, which some have termed "induced seismicity," and some state regulatory agencies have modified their regulations to account for such induced seismicity; and
- ongoing or proposed studies on the environmental impacts of hydraulic fracturing could spur initiatives to further regulate hydraulic fracturing.

We currently disclose information regarding the components and chemicals used in the hydraulic-fracturing process for all US onshore areas in which we operate through the website for the public registry FracFocus.org, which is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council.

Additional Information See Items 1. and 2. Business and Properties – Risk and Insurance Program and Item 1A. Risk Factors.

Risk and Insurance Program

As protection against financial loss resulting from many, but not all operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production income), employer's liability, third-party liability, worker's compensation insurance and certain insurance related to cyber security. We maintain insurance at levels that we believe are appropriate and consistent with industry practice. We regularly review our potential risks of loss and the cost and availability of insurance and the company's ability to sustain uninsured losses, and revise our insurance program accordingly.

Availability of insurance coverage, subject to customary deductibles and recovery limits, for certain perils such as war or political risk is often excluded or limited within property policies. We are, however, actively looking to secure additional coverages for political risks in Jordan and Egypt. In Israel and Equatorial Guinea, we insure against acts of war and terrorism in addition to providing insurance coverage for normal operating hazards facing our business. Additionally, as being part of

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critical national infrastructure, the Israel offshore and onshore assets are included in a special property coverage afforded under the Israeli government's Property Tax and Compensation Fund Law; however, the amount of financial recovery through the fund is not guaranteed.

We have a risk assessment program that analyzes safety and environmental hazards, including cyber threats, and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We also use third-party consultants to help us identify and quantify our risk exposures at major facilities. We have a robust prevention program and continue to manage our risks and operations such that we believe the likelihood of a significant event is remote. However, if an event occurs that is not covered by insurance, not fully protected by insured limits or our non-operating partners are not fully insured, it could have a material adverse impact on our financial condition, results of operations and cash flows. See Item 1A. Risk Factors - *The insurance we carry is insufficient to cover all of the risks we face, which could result in significant financial exposure.*

Competition

The crude oil and natural gas industry is highly competitive. We encounter competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic data and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies, state-controlled national oil companies, independent crude oil and natural gas companies, service companies engaging in exploration and production activities, drilling partnership programs, private equity, and individuals. Many of our competitors are large, well-established companies. Such companies may be able to pay more for seismic information and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

In addition, as we continue to expand our midstream services, we will face a high level of competition, including major integrated crude oil and natural gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store or market natural gas. As we seek to continue to provide midstream services to additional third party producers, we will also face a high level of competition. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas or NGLs.

See Item 1A. Risk Factors - *We face significant competition and many of our competitors have resources in excess of our available resources.*

Employees

As of December 31, 2018, we had 2,330 full-time employees.

Offices

Our principal corporate office is located at 1001 Noble Energy Way, Houston, Texas, 77070. We maintain additional regional offices in the US, Israel, Cyprus, Egypt, Equatorial Guinea, and Cameroon.

Title to Properties

We believe that our title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that would not materially detract from the value of the interests or materially interfere with their use in our operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under PSCs or exploration licenses. We have also dedicated certain of our US onshore acreage to Noble Midstream Partners for the provision of midstream services to us.

Furthermore, while our DJ Basin assets are primarily held by production, other assets, such as our Eagle Ford Shale and Delaware Basin properties, are held primarily through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas or exercise options with land owners to extend leases. Failure to meet these obligations may result in the loss of a lease.

Title Defects Subsequent to a lease or fee interest acquisition transaction, the buyer usually has a period of time in which to examine the leases for title defects. Adjustments for title defects are generally made within the terms of the sales agreement, which may provide for arbitration between the buyer and seller.

Conflicts with Surface Rights Mineral rights are property rights that include the right to use land surface that is reasonably necessary to access minerals beneath. Lawsuits regarding conflicts between surface rights and mineral rights are currently pending in several states. In several cases, owners of surface rights are suing various companies to prevent companies from using their land surface to drill horizontal wells to explore for or produce hydrocarbons from neighboring mineral tracts. If a plaintiff were to prevail in such a case, it could become more difficult and expensive for a company to place multi-acre well pads and/or limit the length of horizontal wells drilled from a pad.

Available Information

Our website address is *www.nblenergy.com.* Available on this website under “Investors – Financial Information – SEC Filings,” free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, Forms 3, 4 and 5 filed on behalf of directors and executive officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC. Alternatively, you may access these reports at the SEC’s website at *www.sec.gov*.

Also posted on our website under “Our Story – Transparency – Corporate Governance – Committee Charters,” and available in print upon request made by any shareholder to the Investor Relations Department, are charters for our Audit Committee, Compensation, Benefits and Stock Option Committee, Corporate Governance and Nominating Committee, and Safety, Sustainability and Corporate Responsibility Committee. Copies of the Code of Conduct and the Code of Ethics for Chief Executive and Senior Financial Officers (the Codes) are also posted on our website under the “Other Governance Documents” section. Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

Item 1A. Risk Factors

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. There may be additional risks that are not presently material or known. You should carefully consider each of the following risks and all other information set forth in this Annual Report on Form 10-K. If any of the events described below occur, our business, financial condition, results of operations, cash flows, liquidity or access to the capital markets could be materially adversely affected.

The oil and gas industry is cyclical and crude oil, NGL and natural gas prices are volatile. A reduction in these prices could have a material adverse effect on our operations, our liquidity, and the price of our common stock.

Our ability to operate profitably, maintain adequate liquidity, grow our cash flow and pay dividends or repurchase our common stock depend upon the prices we receive for our crude oil, NGL and natural gas production. Commodity prices are cyclical and subject to global supply and demand dynamics.

A prolonged or substantial decline in commodity prices, including declines in commodity forward price curves or volatility in location-basis differentials, may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, NGLs and natural gas that we can produce economically, leading to shut-in or early abandonment of producing wells, including low-margin US onshore wells, and increased capital requirements for abandonment operations;
- certain properties in our portfolio becoming economically unviable;
- impairments of proved or unproved properties or other long-lived assets;
- use of cash flow to satisfy minimum obligations under throughput agreements if production is suspended;
- reduction, or suspension, of our future capital investment programs, resulting in a reduced ability to develop or replace our reserves;
- delay, postponement or cancellation of some of our exploration or development projects;
- inability to meet exploration or continuous drilling commitments, leading to loss of leases or exploration rights;
- loss of undeveloped acreage if we are unable to make scheduled delay rental payments or loss of developed acreage if our production is shut-in;
- divestments of properties to generate funds to meet cash flow or liquidity requirements;
- limitations on our financial condition, liquidity, including access to sources of capital, such as debt and equity, and/or ability to finance planned capital expenditures and operations;

- failure of our partners to fund their share of development costs or obtain financing, which could result in delay or cancellation of future projects, thus limiting our growth and future cash flows;
- inability to meet scheduled interest and/or debt payments or payments due under operating or capital leases;
- a series of credit rating downgrades or other negative rating actions, which could increase our future cost of financing and may increase our requirements to post collateral as financial assurance of performance under certain other contracts, which, in turn, could have a negative impact on our liquidity and our ability to access the commercial paper market;

- changes in corporate structure that could lead to loss of key personnel and interrupt our business activities;
- reduction or suspension of dividends or repurchases of our common stock;
- declines in our stock price;
- additional counterparty credit risk exposure on commodity hedges and joint venture receivables; and
- a reduction in the carrying value of goodwill.

Our commodity price hedging arrangements in place will not fully mitigate the effects of price volatility and may also curtail benefits from future increases in commodity prices.

Markets and prices for crude oil, NGLs and natural gas depend on factors beyond our control, factors including, among others:

- global demand for crude oil, NGLs and natural gas, as impacted by economic factors that affect gross domestic product growth rates of countries around the world;
- global supply for crude oil, NGLs and natural gas, as impacted by OPEC and non-OPEC countries (e.g. US, Russia, Canada);
- technology advances that increase crude oil, NGL and natural gas production, thereby increasing supply;
- new technologies that promote fuel efficiency or fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and impact demand for crude oil as a transportation fuel and reduce energy consumption;
- the price and availability of alternative fuels and battery storage and the long-term impact on the crude oil market of the use of natural gas and electricity as an alternative fuel for road transportation or the use of natural gas as fuel for electricity generation impacting the demand for electricity;
- developments in the global LNG market, including exports from the US;
- geopolitical conditions and events, including generational leadership or regime changes, changes in government energy policies, including imposed price controls and/or product subsidies, the impact of trade embargoes or imposed tariffs, or instability/armed conflict in hydrocarbon-producing regions;
- fluctuations in exchange rates of the US dollar, the currency in which the world's crude oil trade is generally denominated;
- periods when production surpasses local pipeline/rail transportation and/or refining capacity, as is currently the case in the Delaware Basin, which in turn results in transportation constraints and significant discounts to our realized prices;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- the effectiveness of worldwide conservation measures;
- weather conditions;
- access to government-owned and other lands for exploration and production activities; and
- domestic and foreign governmental regulations and taxes.

Sector cost inflation could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and third-party oilfield equipment materials and service costs are also subject to supply and demand dynamics. During periods of decreasing levels of industry exploration and production, the demand for, and cost of, drilling rigs and oilfield services decreases. Conversely, during periods of increasing levels of industry activity, the demand for, and cost of, drilling rigs and oilfield services increases. As a result, drilling rigs and oilfield services may not be available at rates that provide a satisfactory return on our investment.

As commodity prices have strengthened, the demand for oilfield services and infrastructure, particularly in US onshore basins, has risen, leading to cost inflation for the drilling, completion and operating of wells, and for the construction and/or access to necessary oil and gas infrastructure, including access to gathering facilities, transportation and/or takeaway pipelines driven by growing production volumes. Transportation bottlenecks or infrastructure limitations caused by the increased utilization may lead to competitive pricing pressures in certain basins. As a result, there is pressure on operating margins and capital efficiency in US onshore basins, including those in which we operate.

If this trend continues, and if commodity prices increase, we expect industry exploration and production activities to continue to increase, resulting in even higher demand for oilfield equipment services, which could result in significant sector price inflation. In addition, in basins of relatively higher activity, scarcity of competent service personnel may impact our ability to execute our exploration and development plans in a timely and profitable manner.

Concentration of capital in, and production and cash flows from, certain operations may increase our exposure to risks enumerated herein.

A significant portion of our production and revenues is highly concentrated and is generated from a limited number of conventional deepwater wells. These wells, located offshore Israel and offshore Equatorial Guinea, contributed approximately 20% of our 2018 total crude oil, NGL and natural gas revenues and 26% of our 2018 total consolidated sales volumes. In addition, we have a major concentration of reserves offshore Israel, with approximately 43% of our year-end 2018 proved reserves attributable to this area.

Although we carry contingent business interruption insurance for these producing assets, as well as other insurance, the insurance is insufficient to cover all potential risks.

We also have significant concentrations of capital and production in unconventional basins including the DJ Basin, Delaware Basin and Eagle Ford Shale, and we expect to invest approximately 70% of our total capital investment program to development activities in these areas in 2019. Restrictions in land access or permitting, rapid changes in drilling and completion technology, significant increases in drilling and completion costs, lack of availability of downstream services, including access to gathering facilities, transportation and/or takeaway pipelines, lack of reliable power or electricity infrastructure, changes in regulations and other risks impacting these areas, as enumerated in certain risk factors described herein, can have immediate, significant negative impacts on our production, cash flows, profitability and financial position.

We face various risks associated with the trend toward increased anti-oil and gas development activity.

In recent years, we have seen significant growth in opposition to oil and gas development both in the US and globally.

Companies in our industry can be the target of opposition to hydrocarbon development from stakeholder groups, including national, state and local governments, regulatory agencies, non-government organizations and public citizens. This opposition is focused on attempting to limit or stop hydrocarbon development in certain areas. Examples of such opposition include: efforts to reduce access to public and private lands; delaying or canceling permits for drilling or pipeline construction; limiting or banning industry techniques such as hydraulic fracturing, and/or adding restrictions on the use of water and associated disposal; imposition of set-backs on oil and gas sites; delaying or denying air-quality permits; advocating for increased regulations, punitive taxation, or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm.

We have experienced these efforts in Colorado, recently and in the past, and it is likely they will continue into the future. For example, the State of Colorado General Assembly is currently developing a framework for future oil and gas development in the State. This initiative, together with increased pressure to allow local governments to control oil and gas operations within their borders, could result in new regulations that limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration or development in areas where we operate. We cannot predict the outcome of these initiatives or their impact on our operations.

Recent efforts by the US Administration to modify federal oil and gas related regulations could intensify the risk of anti-development efforts from grass roots opposition.

Our need to incur costs associated with responding to these anti-development efforts, including legal challenges, or complying with any new legal or regulatory requirements resulting from these efforts, could have a material adverse effect on our business, financial condition and results of operations.

Discoveries or acquisitions of reserves are needed to avoid a material decline in reserves and production.

The production rates from oil and gas properties generally decline as reserves are depleted, while related per unit production costs generally increase due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future crude oil, NGL and natural gas production will decline materially as reserves are produced unless we conduct successful exploration and development activities, such as identifying additional producing zones in existing fields, utilizing secondary or tertiary recovery techniques or gaining access to properties containing future proved reserves. Consequently, our future crude oil, NGL and natural gas production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

The marketability of our production is dependent upon access to gathering, transportation and processing facilities, which we may not own or control.

The marketability of our production from our US onshore areas depends in part upon the availability, proximity and capacity of gathering systems, transportation pipelines, rail service, and processing facilities. We deliver crude oil, NGLs and natural gas produced from these areas through midstream infrastructure, the majority of which we do not own and may not control.

We currently rely on state-owned pipeline and transportation systems to deliver our natural gas production from offshore Israel to customers and end users in the region. In addition, with the execution of multiple agreements to supply natural gas to customers in Egypt, we have entered into an agreement to acquire an equity interest in a company that owns the EMG Pipeline, which will connect the Israel pipeline network to Egyptian customers. Initial gas delivery through the EMG Pipeline is expected to occur in 2019 and is pending certain conditions precedent. Offshore Equatorial Guinea, our natural gas production is delivered to onshore processing and storage facilities operated by our partner, and the resulting products, as well as our crude oil production from Aseng and Alen, are lifted to tankers owned by third-parties.

Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. In addition, the lack of availability of, or capacity on, third-party systems and facilities, including those owned by Noble Midstream Partners, could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Further, the inability of third-party processors, over whom we have no control, to meet anticipated facility expansion deadlines, or to delay or even cancel projects, in areas where our production is growing, such as in the DJ Basin, could result in curtailment of our production growth and/or shut-in of production. Even where we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical reliability or other reasons, including adverse weather conditions or geopolitical instability.

Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay or curtail production, thereby harming our business and, in turn, our results of operations, cash flows, and financial condition.

Our international operations may be adversely affected by economic or geopolitical developments or by violent acts such as civil disturbances, terrorist acts, regime changes, cross-border violence, war, piracy, or other conflicts.

We have significant international operations in Israel and Equatorial Guinea. We also conduct exploration activities in other international areas. Notwithstanding economic stability clauses, our operations may be adversely affected by economic or political developments, including the following:

- renegotiation, modification or nullification of existing contracts, which may occur pursuant to future regulations enacted as a result of changes in Israel's antitrust, export and natural gas development policies, or the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea, which can increase the amount of revenues that the host government receives from production (government take) or otherwise decrease project profitability;
- loss of revenue, property and equipment as a result of actions taken by host nations, such as expropriation or nationalization of assets or termination of contracts;
- changes in drilling or safety regulations;
- laws and policies of the US and foreign jurisdictions affecting trade, foreign investment, taxation and business conduct;
- potential for Israel natural gas production and regional exports to be interrupted by political conditions and events;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- US and international monetary policies impacting foreign exchange or repatriation restrictions in countries in which we conduct business; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Such economic and political developments could have a negative impact on our results of operations and cash flows and reduce the fair values of our properties, resulting in impairment charges.

In addition, our international operations are located in, or in close proximity to, regions that continue to experience varying degrees of political instability, public protests, territorial or boundary disputes, and terrorist attacks. Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued or escalated civil and political unrest and acts of terrorism in the regions in which we operate could result in curtailment of our operations. In the event that such regions experience civil or political unrest or acts of terrorism, especially in areas where such unrest leads to regime change, our operations there could be materially impaired.

We monitor the economic and political environments of the countries in which we operate. However, we are unable to predict the occurrence of disturbances such as those noted above. In addition, we have limited ability to mitigate their impact.

Civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have the following results, among others:

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increased volatility in global crude oil, NGL and natural gas prices, which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;

- negative impact on the global crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- inability of our personnel, third-party providers or supplies to enter or exit the countries where we conduct operations;
- disruption of our operations due to evacuation of personnel;
- inability to deliver our production due to disruption or closing of transportation routes;
- reduced ability to export our production due to efforts of countries to conserve domestic resources;

- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our purchasers, leading to interruption of commodity deliveries, claims of force majeure, and/or termination of sales contracts, resulting in a reduction in our revenues;
- lack of availability of drilling rigs, oilfield equipment or services if third-party providers decide to exit the region;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- capital market reassessment of risk and reduction of available capital making it more difficult for us and our partners to obtain financing for potential development projects.

Loss of property and/or interruption of our business plans resulting from civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Our Eastern Mediterranean discoveries bear certain technical, geopolitical, regulatory, and financial challenges that could adversely impact our ability to monetize these natural gas assets.

Due to the scale of our Leviathan (Israel) and Aphrodite (Cyprus) discoveries, realization of their full economic value depends on our ability to execute successful phased development scenarios, the failure or delay of which could reduce our future growth and have negative effects on our future operating results. Offshore projects of this magnitude entail significant technical complexities, including subsea tiebacks to a FPSO or production platform, pressure maintenance systems, gas re-injection systems, onshore receiving terminals, or other specialized infrastructure. In addition, we depend on third-party technology and service providers and other supply chain participants for these complex projects. Delays and differences between estimated and actual timing of critical events related to these projects could have a material adverse effect on our results of operations.

We have entered into and are currently negotiating various long-term GSPAs for our Eastern Mediterranean natural gas assets. Some of these agreements require the export of natural gas from either Israel or Cyprus to other countries in the region, such as Egypt and Jordan. These agreements are subject to a variety of risks, including geopolitical, regulatory, financial and other uncertainties. War, political violence, civil unrest or lack of intergovernmental cooperation could affect both our and our counterparties' abilities to cooperate and to perform under these agreements, and could potentially lead to a breach or termination of such agreements. In addition, economic conditions or financial duress of our counterparties could jeopardize their ability to fulfill their payment obligations under these contracts. Furthermore, if material disruptions occur, including events or circumstances constituting force majeure under contract provisions, such that they inhibit us or our counterparties from performing under these GSPAs, or our counterparties are unable to pay us for a sustained period of time, we could incur a significant decline in revenues.

While the State of Israel continues to maintain its ability to generate electricity via coal-fired power plants, as they transition from coal-fired power plants to natural gas-fired power plants, it is becoming more dependent on us and our partners for its source of natural gas supply. Any material disruption in our ability to deliver natural gas to the State of Israel could have a material impact on our expected profitability, financial performance and reputation.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

We are increasingly dependent on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves as well as other activities related to our business. Our business partners, including suppliers, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The technologies needed to conduct oil and gas exploration and development activities in deepwater, ultra-deepwater and shale, as well as technologies supporting midstream operations and global competition for oil and gas resources make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. Supervisory control and data acquisition (SCADA) based systems are potentially vulnerable to targeted cyber attacks due to their critical role in operations.

Our technologies, systems, networks, and those of our business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

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- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber attack on a supplier or service provider could result in supply chain disruptions which could delay or halt a development project, effectively delaying the start of cash flows from the project;
- a cyber attack on a third-party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;
- a cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- a cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;
- a cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a deliberate corruption of our financial or operational data, or data theft, could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions, including use of social engineering schemes and/or ransomware, could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Our implementation of various controls and processes to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

We are subject to increasing governmental regulations and environmental requirements that may restrict our access to land and/or cause us to incur substantial incremental costs.

Our industry is subject to complex laws and regulations adopted or promulgated by international, federal, state and local authorities relating to the exploration for, and the development, production and marketing of, crude oil, NGLs and natural gas. As the various government and/or regulatory bodies issue or rescind various regulations, our operations are subject to significant volatility in response to the issuance, interpretation and application of these regulations.

Examples of factors which reduce our land access, including loss of access to land for which we own mineral rights, reduced ability to obtain new leases, or loss of rights granted under surface use agreements, rights-of-way, surface leases or other easement rights, include, among others:

- new municipal, state or federal land use regulations, which may restrict drilling locations or certain activities such as hydraulic fracturing;
- local and municipal government control of land or zoning requirements, which can conflict with state law and deprive land owners of property development rights;
- landowner, community and/or governmental opposition to infrastructure development;
- regulation of federal and Indian land by the BLM; and
- the presence of threatened or endangered species or of their habitat.

In the state of Colorado, for example, since 2014 we have encountered citizen driven ballot initiatives and other legislative proposals to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations. See Items 1. and 2. Business and Properties – Regulations – Colorado.

Changes in price controls, taxes and environmental laws relating to our industry also have the ability to substantially affect crude oil, NGL and natural gas production, operations and economics. Environmental laws, in particular, can change frequently, often become stricter and at times may force us to incur additional costs as changes are implemented.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Additionally, the accidental and/or unpermitted discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to liabilities on our part to government agencies and/or third parties, and may require us to incur

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costs to achieve remediation objectives and/or requirements. See Item 8. Financial Statements and Supplementary Data – Note 11. Commitments and Contingencies – Colorado Air Matter.

Noncompliance with existing or future legislation or regulations could potentially result in an increased risk of civil or criminal fines or sanctions. Fines or sanctions associated with a well incident or spill could well exceed the actual cost of containment and cleanup. In addition, we cannot always predict with certainty how agencies or courts will interpret existing laws and regulations or the effect these interpretations may have on our business or financial condition.

Restricted land access, further expansion of environmental, safety and performance regulations or an increase in liability for drilling or production activities, including punitive fines, may have one or more of the following impacts on our business:

- reduce our proved reserves;
- reduce our ability to explore for new proved reserves;
- increase exploratory and development well drilling costs, operating or other costs;
- delay, or preclude, project development resulting in longer development cycle times;
- disrupt or prohibit our ability to construct or operate midstream assets;
- divert our cash flows from capital investments in order to maintain liquidity;
- increase or remove liability caps for claims of damages from oil spills;
- increase our share of civil or criminal fines or sanctions for actual or alleged violations if a well incident were to occur; and
- limit our ability to obtain additional insurance coverage, at a level that balances the cost of insurance and our desired rates of return, to protect against any increase in liability.

Any of the above operating or financial factors could have a material adverse effect on our business, financial condition, results of operations, and cash flows and may result in a reduction of the fair value of our properties or reduce our financial flexibility. Because we strive to achieve certain levels of return on our projects, an increase in our financial responsibility could result in certain of our planned projects becoming uneconomic. See Items 1. and 2. Business and Properties – Regulations.

Our operations may be adversely affected by changes in the fiscal regimes and related government policies, tax laws and regulations in the US and other countries in which we operate.

Fiscal regimes impact oil and gas companies through laws and regulations governing resource access, along with government participation in oil and gas projects, royalties and taxes. We operate in the US and other countries whose fiscal regimes may change over time. Changes in fiscal regimes result in an increase or decrease in the amount of government financial take from developments, and a corresponding decrease or increase in the revenues of an oil and gas company operating in that particular country. For example, a significant portion of our production comes from Israel and Equatorial Guinea; therefore, changes in or uncertainties related to the fiscal regimes or energy policies of these countries could delay or reduce the profitability of our development projects, and/or render future exploration and development projects uneconomic.

The elimination of tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-US taxes (including the imposition of, or increases in production, severance or similar taxes) could also have a significant impact on our operations and financial performance. For example, on December 22, 2017, the US Congress enacted tax reform legislation known as the Tax Cuts and Jobs Act (Tax Reform Legislation). The Tax Reform Legislation is complex and far-reaching, making sweeping modifications to the Internal Revenue Code including a lower corporate tax rate, changes to credits and deductions, and a move to a territorial system for corporations that have overseas earnings.

Periodically, other legislative amendments may be proposed that, if enacted into law, would make additional significant changes to US federal and state income tax laws, such as (i) the elimination of the immediate deduction for intangible drilling and development costs and (ii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future, or the timing of any such action. Further, we cannot predict how government agencies or courts will interpret existing regulations and tax laws, including Tax Reform Legislation, or the effect such interpretations could have on our business.

Changes in fiscal regimes, including changes in tax laws and regulations, have long-term impacts on our business strategy, and fiscal uncertainty makes it difficult to formulate and execute capital investment programs. The implementation of new, or the modification of existing, laws or regulations increasing the tax costs on our business could disrupt our business plans and negatively impact our operations and our stock price in the following ways, among others:

- restrict resource access or investment in lease holdings;
- limit or cancel exploration and/or development activities, which could have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- negatively impact our and/or our partners' ability to obtain financing;
- reduce the profitability of our projects, resulting in decreases in net income and cash flows with the potential to make future investments uneconomical;

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- result in currently producing projects becoming uneconomic, to the extent fiscal changes are retroactive, thereby reducing the amount of proved reserves we record and cash flows we receive, and possibly resulting in asset impairment charges;
- require that valuation allowances be established against deferred tax assets, with offsetting increases in income tax expense, resulting in decreases in net income and cash flow; and/or
- restrict our ability to compete with imported volumes of crude oil or natural gas.

A change in international and/or US federal and state climate policy could have a significant impact on our operations and profitability.

Domestic and international responses to climate and related energy issues are matters of public policy consideration. We are currently in a period of increasing uncertainty as to these matters and, at this time, it is difficult to anticipate how the current US Administration, or other entities, may act on existing or new laws and regulations. As compared with certain large multi-national, integrated energy companies, we do not conduct fundamental research regarding the scientific inquiry of climate change. However, we will continue to closely monitor all relevant developments in this regard. Changes in international, federal or state laws and regulations regarding climate policy could have a significant negative impact on our ability to explore for and develop crude oil and natural gas resources or reduce demand for our products.

In recent years, international, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the US Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of states in the US have taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. For a description of existing and proposed greenhouse gas rules and regulations, see Items 1. and 2. Business and Properties – Regulations.

Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or other entities may make claims against us for alleged personal injury, property damage, or other potential liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could impact our operations and could have an adverse impact on our financial condition.

Additionally, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes, drought and snow or ice storms, as well as rising sea levels. Extreme weather conditions can interfere with our production and increase our costs, and damage resulting from extreme weather may not be fully insured.

Our operations require us to comply with a number of US and international laws and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business.

Our operations require us to comply with complex and frequently-changing US and international laws and regulations, such as those involving anti-corruption, competition and antitrust, anti-boycott, anti-money laundering, import-export control, marketing, environmental and/or taxation.

For example, the US Foreign Corrupt Practices Act (FCPA) and similar laws and regulations generally prohibit improper payments to foreign officials for the purpose of obtaining or keeping business. We conduct some of our operations in developing countries that have relatively underdeveloped legal and regulatory systems compared to more developed countries. These countries generally are perceived as presenting an increased risk of corruption. Additionally, certain of our operations involve the use of agents and other intermediaries whose conduct and actions could be imputed to us by anti-corruption enforcement authorities. Violations of the FCPA or other anti-corruption laws could subject us to substantial fines or sanctions and impair our ability to do business.

The import/export of equipment and supplies necessary for oil and gas exploration and development activities, as well as the export of crude oil, liquids and natural gas production are regulated by the import/export laws of the US and other countries in which we operate. In the US, certain items required for oil and gas development activities may be considered “dual-use”, having both commercial and military applications and, therefore, may be subject to specific import or export restrictions. In addition, the US government imposes economic and trade sanctions against certain foreign countries and regimes. The sanctions are based on US foreign policy and national security goals and may change over time.

As a developer, owner and operator of crude oil and natural gas properties, we are subject to various laws and regulations relating to the discharge of materials into, and the protection of, the environment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. See *We are subject to increasing governmental regulations and environmental*

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requirements that may restrict our access to land and/or cause us to incur substantial incremental costs, above, and Item 8. Financial Statements and Supplementary Data – Note 11. Commitments and Contingencies.

Federal, state and local hydraulic fracturing and water disposal legislation and regulation could increase our costs or restrict our ability to produce crude oil, NGLs and natural gas economically and in commercial quantities.

While hydraulic fracturing has been utilized in oil and gas development for decades, certain parties have called for further study of the technique's alleged environmental and health effects, for additional regulation of the technique and, in some cases, for a moratorium or ban on the use of hydraulic fracturing. Because of elevated public sensitivity around the topic, federal, state and local governments are continually conducting studies, evaluating their regulatory programs and considering additional requirements on and regulation of hydraulic fracturing practices. At the national level, proposals have been introduced from time to time in the US Congress that, if implemented, would subject hydraulic fracturing to further regulation, thereby limiting its use or increasing its cost.

Federal agencies addressing hydraulic fracturing under existing authorities include the EPA and the BLM, under the US Department of the Interior. In 2017, an executive order was signed directing the EPA and the BLM to review their rules and, if appropriate, initiate rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. Accordingly, the EPA and the BLM have taken actions to delay or rescind certain requirements related to hydraulic fracturing activities. See Items 1. and 2. Business and Properties – Hydraulic Fracturing.

Each of the states, as well as certain localities, where we operate have adopted or may adopt regulations on drilling activities in general or hydraulic fracturing in particular that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, a number of local communities in Colorado have attempted to increase regulatory requirements on crude oil and natural gas development. In addition, some state regulatory agencies have modified their regulations to account for potential induced seismicity with regard to the operation of injection wells used for waste disposal.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the US Department of Energy, the US Geological Survey, and the US Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

We are dependent on the use of hydraulic fracturing practices to produce commercial quantities of crude oil and natural gas, particularly from wells in our US onshore basins. Additional federal, state or local restrictions on hydraulic fracturing, water disposal or other drilling activities that may be imposed in areas where we conduct business, such as US onshore, could significantly increase our operating, capital and compliance costs, as well as delay or halt our ability to develop crude oil, NGL and natural gas reserves. See Items 1. and 2. Business and Properties – Regulations and – Hydraulic Fracturing.

Exploration, development and production activities carry inherent risk. These activities, as well as natural disasters or adverse weather conditions, could result in liability exposure or the loss of production and revenues.

Our operations are subject to hazards and risks inherent in the drilling, production and transportation of crude oil, NGLs and natural gas, including:

- pipeline ruptures and spills;
- fires, explosions, blowouts and well cratering;

- equipment malfunctions and/or mechanical failure on high-volume, high-impact wells;
- malfunctions of, or damage to, gathering, processing, compression and transportation facilities and equipment and other facilities and equipment utilized in support of our crude oil, NGL and natural gas operations;
- leaks or spills occurring during the transfer of hydrocarbons from an FPSO to an oil tanker;
- loss of product occurring as a result of transfer to a truck or rail car or train derailments;
- leakage or loss of access to hydrocarbons resulting from formations with abnormal pressures and basin subsidence;
- release of pollutants; and
- spills, leaks or discharges of fluids used in or produced in the course of operations, especially those that reach surface water or groundwater.

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Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, causing the loss of equipment or otherwise negatively impacting the projected economic performance of our projects. In addition, our ability to deliver product pursuant to long-term supply contracts could be negatively impacted, resulting in additional financial exposure in the event we cannot fully deliver the contract quantities.

Any of these risks or hazards can result in injuries and/or deaths of employees, supplier personnel or other individuals, loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, regulatory investigations and administrative, civil and criminal penalties or restricted access to our properties.

In addition, our operations and financial results could be significantly impacted by adverse weather conditions and natural disasters in the areas we operate including:

- hurricanes, tropical storms, windstorms, or "superstorms," which could affect our operations in areas such as Texas;
- winter storms and snow, which could affect our operations in the DJ Basin;
- extremely high temperatures, which could affect our midstream or third-party gathering and processing facilities in the DJ Basin and Texas;
- severe droughts, which could result in new restrictions on water usage in the DJ Basin and Texas;
- harsh weather and rough seas offshore international locations, which could limit exploration activities; and
- other natural disasters.

Any of these can result in loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, or restricted access to our properties.

Development drilling may not result in commercially productive quantities of crude oil and natural gas reserves from unconventional or conventional resources.

We depend on development projects to provide sustained cash flows after investment and attractive financial returns. However, development drilling is not always successful and the profitability of development projects may change over time.

In new development areas, including certain shale formations, available data may not allow us to completely know the extent of the reservoir or the best locations for drilling development wells. Therefore, a development well we drill, or in which we participate, may be a dry hole, may result in noncommercial quantities of hydrocarbons or may be less productive than our initial estimates.

We expect to invest significant amounts of capital to continue development of our US onshore unconventional resources and to progress the development of the Leviathan field project. In unconventional basins, development is highly dependent on costs of equipment and services, the use of technologies to drive capital and cost efficiencies in drilling and completion, and the availability of and access to midstream infrastructure. Even if development drilling is successful and we find commercial quantities of reserves, we may encounter difficulties or delays in completing development wells. For example, frontier areas or less developed onshore areas may not have adequate infrastructure for gathering, transportation or processing, and production may be delayed until such infrastructure is constructed.

Exploratory drilling subjects us to risks and may not result in the discovery of commercially productive reservoirs.

Exploratory drilling requires significant capital investment and does not always result in commercial quantities of hydrocarbons or new development projects. In addition, exploratory drilling activities may be curtailed, delayed or canceled, or development plans may change, resulting in significant exploration expense, as a result of a variety of factors, including unexpected drilling conditions and pressure or other irregularities in formations. Furthermore, remote locations may make it more difficult and time-consuming to transport personnel, equipment and supplies, and we may face more difficult environments, such as oil sands, deepwater, or ultra-deepwater, in our efforts to seek new reserves, and may need to develop or invest in new technologies. These operating environments, and potential for harsh weather, increase cost as well as drilling risk.

Exploratory dry holes can occur because seismic data and other technologies we use to determine potential exploratory drilling locations do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. In addition, a well may be successful in locating hydrocarbons, but we and our partners may decide not to develop the prospect due to other considerations.

In addition, for certain capital-intensive offshore projects, it may take several years to evaluate the future potential of an exploratory well and make a determination of its economic viability, resulting in delays in cash flows from production start-up and a lower return on our investment.

We hold working interests in certain areas, including offshore areas of Cyprus, Cameroon, Gabon and Newfoundland (Canada) where there is minimal or no crude oil, NGL or natural gas production, and in certain cases, limited infrastructure. If commercial quantities of hydrocarbons are discovered, areas with minimal or no current production must begin to address topics such as sector regulation and distribution of government proceeds from hydrocarbon sales, the results of which could

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have a negative impact on our business. We may not be able to compensate for or fully mitigate these risks. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Failure to adequately fund continued capital expenditures could adversely affect our properties.

Our exploration, development, and acquisition activities require capital expenditures to achieve production and cash flows. In particular, major offshore projects have a multi-year long development cycle time, which means that development spending occurs for several years before the project begins producing hydrocarbons and generating cash flows. As examples, assets and infrastructure for export of natural gas from Leviathan require a multi-billion dollar investment prior to production startup. Furthermore, while our DJ Basin assets are primarily held by production, other assets, such as our Eagle Ford Shale and Delaware Basin properties, are held primarily 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.

Historically, we have funded our capital expenditures through a combination of cash flows from operations, our Revolving Credit Facility (defined below), debt and equity issuances, and occasional sales of assets. Future cash flows from operations are subject to a number of variables, as enumerated herein. If commodity prices decline for an extended period of time, we will evaluate our level of capital spending and likely reduce our investment program. As a result, we will have less ability to replace our reserves through drilling operations and may elect to forfeit our ownership interests or rights to participate in some properties, resulting in lower production over time as compared with prior years. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2019 Capital Investment Program.

Our Midstream reportable segment derives a substantial portion of its revenue from unaffiliated, third party customers. If any of these customers changes its business strategy, alters current drilling and development plans on dedicated acreage, or otherwise significantly reduces the volumes of crude oil, natural gas, produced water or fresh water with respect to which we perform midstream services, our Midstream revenues would decline and have negative impacts on our business, financial condition, results of operations, and cash flows.

We have numerous commercial agreements to provide midstream services and crude oil sales for unaffiliated third-party customers, some of whom are non-investment grade. Accordingly, because we derive a substantial portion of our midstream revenue from these commercial agreements, we are subject to the operational and business risks of these customers, the most significant of which include the following:

- a reduction in or slowing of customer drilling and development plans on our dedicated acreage, which would directly and adversely impact demand for our midstream services;
- the volatility of crude oil, natural gas and NGL prices, which could have a negative effect on our customers' drilling and development plans on our dedicated acreage or ability to finance their operations and drilling and completion costs on our dedicated acreage;
- the availability of capital on an economic basis for our customers to fund their exploration and development activities;
- drilling and operating risks associated with customer operations on our dedicated acreage;
- downstream processing and transportation capacity constraints and interruptions, including the failure of our customers to have sufficient contracted processing or transportation capacity; and
- adverse effects of increased or changed governmental and environmental regulation or enforcement of existing regulation.

Further, we have no control over our customers' business decisions and operations, and our customers are under no obligation to adopt a business strategy that is favorable to us. Thus, we are subject to the risk of cancellation of planned development, breach of commitments with respect to future dedications, and other non-payment or non-performance by our customers, including with respect to our commercial agreements, which do not contain minimum volume commitments.

Our ability to produce crude oil, NGLs and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose

of or recycle the water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water and results in the production of waste water. For example, the hydraulic fracturing process, which we employ to produce commercial quantities of crude oil, NGLs and natural gas from many reservoirs, requires the use and disposal of significant quantities of water. In certain regions, there may be insufficient local capacity to provide a source of water for drilling activities. In those cases, water must be obtained from other sources and transported to the drilling site, adding to the development cost. Waste water from oil and gas operations often is disposed of via underground injection. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection, which is leading to increased public scrutiny of injection safety.

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The development of new environmental initiatives or regulations related to acquisition, withdrawal, storage and use of surface water or groundwater, or treatment and discharge of water waste, may limit our ability to use techniques such as hydraulic fracturing, increase our development and operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted and all of which could have an adverse effect on our operations and financial condition. See Items 1. and 2. Business and Properties – Hydraulic Fracturing.

A negative shift in investor sentiment of the oil and gas industry could adversely affect our ability to raise debt and equity capital.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas and related infrastructure projects.

Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

We face various risks associated with global populism and general political uncertainty.

Following the 2008/2009 global financial crisis, the world has experienced lower economic growth versus the levels attained in previous decades. Recent trade tensions and tariff disputes, including retaliation to such policies which have the potential to escalate into global trade wars, have also contributed to a slowing of global trade activities further compounding concerns around jobs, economic well-being and wealth distribution. Globally, certain individuals and organizations are attempting to focus the public's attention on income and wealth distribution and implement income and wealth redistribution policies.

Recent events have intensified these risks. Globally, and in the US, the growing trends toward populism and political polarization have resulted in uncertainty regarding potential changes in regulations, fiscal policy, social programs, domestic and foreign relations and international trade policies and tariffs.

Changes in relationships among the US, China and Russia, and/or among China, Russia and other countries, have potentially significant impacts on the global balance of power, as well as on global trade, with resultant impacts on both global and local economies. In addition, changes in the relationship between the US and its neighbors is currently impacting commerce and trade across the North American continent. In Europe, the populist movement has resulted in the Brexit vote and increasing populist demands coupled with rising nationalism could have a negative impact on economic policy and consequently pose a potential threat to economic growth as well as the unity of the European Union.

Trade and/or tariff disputes could result in increased costs or shortages of materials and supplies the oil and gas industry relies on to produce, process and transport its oil and gas production. Our ability to respond to these developments or comply with any resulting new legal or regulatory requirements, including those involving economic and trade sanctions, could reduce our ability to negotiate the sale of our products, increase our costs of doing business, reduce our financial flexibility and otherwise have a material adverse effect on our business, financial condition and results of our operations.

Indebtedness may limit our liquidity and financial flexibility.

At December 31, 2018, we had $6.6 billion of consolidated debt, of which $560 million relates to Noble Midstream Partners, and indebtedness represented 39% of our total book capitalization (sum of debt plus shareholders' equity). Indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
-

a covenant contained in our Credit Agreement provides that our total debt to capitalization ratio (as defined in the Credit Agreement) may not exceed 65% at any time, which may make additional borrowings more expensive, thereby affecting our flexibility in planning for, and reacting to, changes in the economy and our industry;

- additional future financing for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt in order to fund our exploration, development and acquisition activities. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service

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our debt depends on future performance. General economic conditions, commodity prices, and financial, business and other factors may affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt.

In addition, a downgrade or other negative rating action could affect our requirements to post collateral as financial assurance of performance under certain contractual arrangements, such as pipeline transportation contracts, crude oil and natural gas sales contracts, work commitments and certain abandonment obligations. A lowering of our debt credit rating may negatively affect the cost, terms, conditions and/or availability of future financing, including access to the commercial paper market, and lower ratings will increase the interest rate and fees we pay on our Revolving Credit Facility. These actions, in turn, could result in negative impacts on our business, financial condition and liquidity. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in highly competitive areas of crude oil and natural gas exploration, development, acquisition and production. We face intense competition from various types of competitors ranging from large multi-national, integrated oil and gas companies, to state-controlled national oil companies, to independent oil and gas companies, to privately backed oil and gas equity funds, to name a few.

We also face competition in a number of areas such as:

- acquiring desirable producing properties or new leases for future exploration;
- acquiring or increasing access to gathering, transportation and processing services and capacity;
- marketing our crude oil, NGL and natural gas production;
- acquiring the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain skills.

Many of our competitors have financial and other resources substantially in excess of those available to us. Such companies may be able to pay more for seismic information and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. This highly competitive environment could have an adverse impact on our business. See Items 1. and 2. Business and Properties – Competition.

Estimates of crude oil, NGL and natural gas reserves are not precise.

Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, NGLs and natural gas that cannot be measured in an exact manner, and there are numerous uncertainties inherent in estimating reserves quantities and their value, including factors that are beyond our control.

In accordance with the SEC's rules for oil and gas reserves reporting, our reserves estimates are based on 12-month average commodity prices; therefore, reserves quantities will change when actual prices increase or decrease. As estimated production, development and abandonment costs are based on year-end economic conditions, reserves quantities will also change when these costs increase or decrease.

Reserves estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- assumed effects of regulations by governmental agencies, including the SEC;
- anticipated development cycle time;
- future development costs;
- future operating and abandonment costs;
- impacts of cost recovery provisions in contracts with foreign governments;
- severance and excise taxes; and
- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of crude oil, NGLs and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows expected from them prepared by different petroleum engineers, or by the same petroleum engineers but at different times, may vary substantially. Estimation of crude oil, NGL and natural gas reserves in emerging areas or areas with limited historical production is inherently more difficult, and we may have less experience in such areas. Accordingly, reserves estimates may be subject to positive or negative revisions, and actual production, revenues and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Any such negative revisions could result in an asset impairment charge.

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Additionally, some of our reserves estimates are calculated using volumetric analysis, which involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. Reserves estimates using volumetric analysis are less reliable than estimates based on a lengthy production history.

In addition, realization or recognition of PUDs will depend on our development schedule and plans. A change in future development plans for PUDs could cause the discontinuation of the classification of these reserves as proved. See Items 1. and 2. Business and Properties – Proved Reserves Disclosures.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies can be involved in various legal proceedings and disputes with landowners, royalty owners, or other operators over matters such as leases, title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements, in the ordinary course of business. For example, in certain states, oil and gas companies are often the target of “legacy lawsuits,” by which a landowner claims that oil and gas operations, often performed many years ago and by another operator, caused pollution or contamination of a property. Various properties we have owned over the past decades potentially expose us to “legacy lawsuit” claims. Similarly, neighboring landowners may allege that current operations cause contamination or create a nuisance.

Because we maintain a diversified portfolio of assets that includes both US and international projects, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. For example, we historically have had to address certain fiscal, antitrust and other regulatory challenges in Israel, including a current lawsuit filed by petitioners alleging we and our partners in Tamar violated antitrust laws through the monopolistic pricing of natural gas to the citizens of Israel. Legal proceedings such as this could result in substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities. These proceedings are subject to the uncertainties inherent in any litigation. We will defend ourselves vigorously in all such matters. However, if we are not able to successfully defend ourselves, there could be a delay or even a halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows.

One of our subsidiaries acts as the general partner of a publicly traded master limited partnership, Noble Midstream Partners, which may involve a potential legal liability.

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

We may be subject to risks in connection with acquisition and divestiture activities.

As part of our business strategy, we have made, and will likely continue to make, acquisitions of oil and gas properties and/or entities that own them. If we are unable to make attractive acquisitions, our future growth could be limited. Moreover, even if we do make acquisitions, they may not result in an increase in our cash flows from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- incorrect estimates or assumptions about reserves, exploration potential or potential drilling locations;
- incorrect assumptions regarding future revenues, including future commodity prices and differentials, or regarding future development and operating costs;
- incorrect assumptions regarding potential synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

Mergers of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger. US antitrust laws require waiting periods and even after completion of a merger, governmental authorities could seek to block or challenge a merger as they deem necessary or desirable in the public interest. We have merged with or acquired other companies in the past. Prevention of a merger by antitrust laws could impair our ability to do business. Furthermore, mergers and acquisitions expose us to potential lawsuits or other obligations not yet anticipated at time of merger or acquisition. Such liabilities and obligations could hinder our ability to fully benefit from the acquired business or assets and negatively impact our financial performance.

The acquisition of a property or business requires management to make complex judgments and assessments, and the accuracy of the assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties

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that we believe to be consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

We also maintain an ongoing portfolio management program to ensure our company is well-positioned with assets that offer growth at financially attractive investment options. Therefore, we may periodically divest certain material assets. We strive to obtain the most attractive prices for our assets; however, various factors can materially affect our ability to dispose of assets on terms acceptable to us. Such factors may include:

- current commodity prices;
- laws and regulations impacting oil and gas operations in the areas where the assets are located;
- willingness of the purchaser to assume certain liabilities such as asset retirement obligations;
- our willingness to indemnify buyers for certain matters; and
- delays in closing.

Inability to achieve a desired price for the assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities which must be settled in the future at amounts that are higher than we anticipated. In addition, although we may successfully divest oil and gas assets, we may retain certain related contracts. For example, although we sold our Marcellus Shale upstream properties in 2017, we retained significant obligations under firm transportation contracts. Our inability to fully commercialize these contracts and reduce the associated financial commitments could result in a decrease in cash flows from operations. In addition, we may be required to recognize losses in accordance with exit or disposal activities. See Item 7. Management's Discussion of Financial Condition and Results of Operations – Liquidity and Capital Resources – Contractual Obligations.

We are exposed to counterparty credit risk as a result of our receivables, hedging transactions and cash investments.

We are exposed to risk of financial loss from joint venture and other receivables. We are the operator on a majority of our joint venture development projects, including Leviathan. As joint venture operator, we pay joint venture expenses and make cash calls on nonoperating partners for their respective shares of joint venture costs. These projects are capital intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs or have liquidity problems resulting in slow payment of joint venture costs that can result in potential delays in our development projects. In addition, some of our joint venture partners are not as creditworthy as we are and may experience credit rating downgrades or liquidity problems that may hinder their ability to obtain financing. Counterparty liquidity problems could result in a delay in receiving proceeds from reimbursement of joint venture costs. Nonperformance by a joint venture partner could result in significant financial losses.

We have cash and cash equivalents deposited with financial institutions, a majority of which is invested in money market funds and short-term deposits with major financial institutions. In addition, our hedging activities may expose us to counterparty credit risk or, in some cases, cause us to incur significant cash settlements. As an entity entering into derivatives transactions under master agreements that are subject to US laws, we are subject to some limitations on our ability to exercise default rights with respect to derivatives transactions with a financially-troubled bank. On January 1, 2019, the US Bank Regulators imposed additional restrictions on counterparties that are parties to certain types of Qualified Financial Contracts (QFCs) with major banks that have been designated as Global Systemically Important Banks (G-SIBs). These QFCs include various master agreements and the financial derivatives transactions that are entered into under such master agreements with G-SIBs as counterparties.

While we monitor the creditworthiness of joint venture partners, purchasers, banks and financial institutions with which we conduct business, we are unable to predict sudden changes in solvency of these counterparties and may be exposed to associated risks. Credit enhancements have been obtained from some parties in the form of parental guarantees, letters of credit or credit insurance; however, not all of our counterparty credit is protected through guarantees or credit support. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a hedge counterparty or financial institution could result in significant financial losses.

Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices.

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into hedging arrangements with respect to a portion of our expected revenues. Our hedges, consisting of a series of derivative instrument contracts, are limited in duration, usually for periods of one to three years. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains if prices rise over the price established by the arrangements. Conversely, our hedging program may be inadequate to protect us from continuing and prolonged declines in the price of crude oil or natural gas. See Item 8. Financial Statements and Supplementary Data – Note 13. Derivative Instruments and Hedging Activities.

The insurance we carry is insufficient to cover all of the risks we face, which could result in significant financial exposure.

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Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters or other catastrophic events such as hurricanes, earthquakes, blowouts, well cratering, fire and explosion, loss of well control, pipeline disruptions, mishandling of fluids and chemicals, and possible underground migration of hydrocarbons and chemicals, any of which can result in damage to or destruction of wells or formations or production facilities, injury to persons, loss of life, or damage to property and the environment. Exploration and production activities are also subject to risk from other disruptive events such as terrorist acts, piracy, civil disturbances, war, and expropriation or nationalization of assets, or other interruptions, such as cyber security breaches, which can cause loss of or damage to our property.

Our insurance program and memberships in domestic and international dedicated oil spill and emergency response organizations may not minimize or fully protect us from losses resulting from damages to or the loss of physical assets or loss of human life, liability claims of third parties, and business interruption (loss of production) attributed to certain assets and including such occurrences as well blowouts and resulting oil spills. We do not have insurance protection against all the risks we face, because we choose not to insure certain risks, insurance is not available at a level that balances the cost of insurance and our desired rates of return, or actual losses may exceed coverage limits. We expect the future availability and cost of insurance to be impacted by events such as hurricanes, earthquakes and other natural disasters. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in areas in which we operate, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor for any legislative or regulatory changes related to exploration and production and its potential impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection, at a level that we can afford considering the cost of insurance and our desired rates of return, against disruption to our operations and cash flows.

If an event, for example, a major offshore incident resulting in significant personal injury and/or environmental and physical damage, occurs that is not covered by insurance or not fully protected by insured limits, it could have a significant adverse impact on our financial condition, results of operations and cash flows. See Items 1. and 2. Business and Properties – Risk and Insurance Program.

Item1B. Unresolved Staff Comments

None.

Item 3. 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. See Item 8. Financial Statements and Supplementary Data – Note 11. Commitments and Contingencies.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock Our common stock, $0.01 par value, is listed and traded on the NYSE under the symbol “NBL.” The declaration and payment of dividends are determined on a quarterly basis and are at the discretion of our Board of Directors and the amount thereof will depend on our results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Dividends On January 29, 2019, our Board of Directors declared a quarterly cash dividend of $0.11 per common share. The dividend will be paid February 25, 2019, to shareholders of record on February 11, 2019. See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Shareholders' Equity.

Transfer Agent and Registrar The transfer agent and registrar for our common stock is Computershare Trust Company N.A., 250 Royall Street, Canton, MA, 02021.

Shareholders' Profile Pursuant to the records of the transfer agent, as of February 7, 2019, the number of holders of record of our common stock was 541.

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Stock Repurchases The following table summarizes repurchases of our common stock occurring in fourth quarter 2018:

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)
10/1/2018 - 10/31/2018	59,006	$ 29.37	—	
11/1/2018 - 11/30/2018	1,630,968	24.57	1,621,076	
12/1/2018 - 12/31/2018	964,927	23.53	964,609	
Total	2,654,901	$ 24.29	2,585,685	$ 455

(1) Includes stock repurchases of 69,216 shares during the period related to 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 fourth quarter 2018, we repurchased and retired 2,585,685 shares of common stock at an average purchase price of $24.19 per share pursuant to the $750 million share repurchase program, authorized by the Board of Directors and announced in February 2018, which expires on December 31, 2020.

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2013 to December 31, 2018. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index and a peer group of companies. The cumulative total return of the common stock of our peer group of companies includes the cumulative total return of our common stock.

Our peer group includes a broad group of US onshore and global exploration and production companies which are further diversified by location and number of resource plays as well as level of integration within the crude oil and natural gas business cycle. Our peer group consists of the following:

Anadarko Petroleum Corp.	Devon Energy Corp.	Noble Energy, Inc.
Apache Corp.	EOG Resources, Inc.	Pioneer Natural Resources Co.
Cabot Oil & Gas Corp.	Hess Corp.	Range Resources Corp.
Chesapeake Energy Corp.	Marathon Oil Corp.	Southwestern Energy Co.
Continental Resources, Inc.	Murphy Oil Corp.	

The comparison assumes $100 was invested on December 31, 2013 in our common stock, in the S&P 500 Index and in our peer group of companies and assumes that all of the dividends were reinvested. In addition, the peer group investment is weighted based upon the market capitalization of each individual company within the peer group.

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Year Ended December 31,	2014	2015	2016	2017	2018
Noble Energy, Inc.	$70.38	$49.73	$58.15	$45.11	$29.47
S&P 500	113.69	115.26	129.05	157.22	150.33
Peer Group	86.06	53.24	76.93	68.75	51.93

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Item 6. Selected Financial Data

(millions, except as noted)	Year Ended December 31, 2018	2017	2016	2015	2014
Revenues and Income					
Total Revenues	$4,986	$4,256	$3,491	$3,183	$5,115
Net Income (Loss) and Comprehensive Income (Loss) Including Noncontrolling Interests	14	(1,050)	(985)	(2,441)	1,214
Net (Loss) Income and Comprehensive (Loss) Income Attributable to Noble Energy	(66)	(1,118)	(998)	(2,441)	1,214
Per Share Data, Attributable to Noble Energy					
(Loss) Earnings Per Share - Basic	(0.14)	(2.38)	(2.32)	(6.07)	3.36
(Loss) Earnings Per Share - Diluted	(0.14)	(2.38)	(2.32)	(6.07)	3.27
Cash Dividends Per Share	0.43	0.40	0.40	0.72	0.68
Year-End Stock Price Per Share	18.76	29.14	38.06	32.93	47.43
Weighted Average Number of Shares Outstanding					
Basic	483	469	430	402	361
Diluted	483	469	430	402	367
Cash Flows					
Net Cash Provided by Operating Activities	$2,336	$1,951	$1,351	$2,062	$3,506
Additions to Property, Plant and Equipment	3,279	2,649	1,541	2,979	4,871
Proceeds from Divestitures [1]	1,999	2,073	1,241	151	321
Proceeds from Issuance of Noble Energy Common Stock, Net of Offering Costs	—	—	—	1,112	—
Proceeds from Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	312	299	—	—
Financial Position					
Cash and Cash Equivalents	$716	$675	$1,180	$1,028	$1,183
Property, Plant and Equipment, Net	18,419	17,502	18,548	21,300	18,143
Goodwill [2]	110	1,310	—	—	620
Total Assets	21,010	21,476	21,011	24,196	22,518
Long-term Obligations					
Long-Term Debt	6,574	6,746	7,011	7,976	6,068
Deferred Income Taxes	1,061	1,127	1,819	2,826	2,516
Asset Retirement Obligations, Noncurrent	762	824	775	861	670
Other	403	421	328	358	417
Total Equity	10,484	10,619	9,600	10,370	10,325

[1] See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

[2] See Item 8. Financial Statements and Supplementary Data – Note 6. Goodwill Impairment.

	Year Ended December 31, 2018	2017	2016	2015	2014
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	130	129	125	112	103
Average Realized Price ($/Bbl)	$62.01	$49.73	$40.39	$45.00	$91.58
Consolidated NGL Sales (MBbl/d)	62	58	54	39	23
Average Realized Price ($/Bbl)	$25.88	$23.40	$14.92	$13.91	$33.75
Consolidated Natural Gas Sales (MMcf/d)	922	1,118	1,397	1,187	992
Average Realized Price ($/Mcf)	$2.76	$3.01	$2.42	$2.44	$3.38
Proved Reserves					

Crude Oil and Condensate Reserves (MMBbls)	457	457	333	307	304
NGL Reserves (MMBbls)	266	229	219	189	128
Natural Gas Reserves (Bcf)	7,231	7,680	5,308	5,549	5,833
Total Reserves (MMBoe)	1,929	1,965	1,437	1,421	1,404
Number of Employees	2,330	2,277	2,274	2,395	2,735

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Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. Our MD&A is presented in the following major sections:

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

EXECUTIVE SUMMARY

Noble Energy Key Metrics (metrics should be reviewed in the context of additional information provided in the links below)

Items 1. and 2. Business and Properties – Sales Volumes, Price and Cost Data

Results of Operations – E&P

Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures

Items 1. and 2. Business and Properties – Proved Reserves Disclosures

Item 8. Financial Statements and Supplementary Data – Supplementary Oil and Gas Information (Unaudited)

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Liquidity and Capital Resources – Cash Flows

Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows
Items 1. and 2. Business and Properties – Sales Volumes, Price and Cost Data

Results of Operations - E&P

Items 1. and 2. Business and Properties – Domestic and International
Liquidity and Capital Resources – Acquisition, Capital Expenditures and Other Exploration Expenditures

Items 1. and 2. Business and Properties – Proved Reserves Disclosures

Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited)

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EXECUTIVE OVERVIEW

Industry Outlook

Crude Oil The global oil and gas industry is cyclical, and crude oil prices are volatile, driven by crude oil supply, which includes OPEC and non-OPEC producers, and global crude oil demand. Building on the prior year's price recovery and higher demand, crude oil prices trended upward for most of 2018, with Brent and WTI crude oil prices reaching a four-year high, in excess of $80 and $70 per barrel, respectively. However, in November 2018, prices suddenly plunged, with Brent and WTI prices falling to nearly $50 and $40 per barrel, respectively, as traders focused on supply economics combined with concerns of slowing global growth.

The outlook for 2019 crude oil prices will continue to depend on supply and demand dynamics, as well as global geopolitical and security factors in crude oil-producing nations. Even if OPEC cuts production, US shale supply is expected to continue to grow due to capital investment in anticipation of the addition of takeaway capacity easing recent bottlenecks, such as in the Delaware Basin. These factors, and the potential for slower global growth and increasing global uncertainty, could suppress crude oil prices. In addition, the spread between WTI and Brent prices has been widening, resulting in comparatively lower prices for US production. However, reductions in industry investment, particularly for conventional crude oil development, will, over time, contribute to production declines, potentially supporting higher prices.

Natural Gas The US domestic natural gas market remains oversupplied as domestic production has continued to grow due to drilling efficiencies, higher incremental volumes of associated gas from oil wells and de-bottlenecking of transportation infrastructure. In contrast to crude oil supply curtailments, there has been little to offset natural gas supply growth, which continues to outpace demand domestically. As a result, natural gas prices remained range-bound in 2018, with an expectation to continue as such in 2019, with natural gas prices at or near current or recent trading levels.

Impact of Current Commodity Prices The chart below shows the historical trend in benchmark prices for WTI crude oil, Brent crude oil and US Henry Hub natural gas.

Development and Operating Costs As commodity prices strengthened, the demand for oilfield equipment, services and infrastructure, particularly in US onshore basins, began to rise, leading to cost inflation for the drilling, completion and operating of wells, and for the construction and/or access to necessary oil and gas infrastructure. As a result, during 2018 there was pressure on operating margins and capital efficiency in US onshore basins, including those in which we operate. With the recent crude oil price decline from mid-2018 highs, the development and operating cost structure has begun to shift downward, and we expect margin pressure will continue into 2019.

Takeaway Capacity With higher commodity prices and the resurgence of US onshore drilling activity, demand increased for access to gathering facilities, transportation and/or takeaway pipelines due to growing production volumes. In the Delaware Basin, midstream suppliers are working to construct new gathering, transportation and processing facilities or to repurpose existing infrastructure in an effort to proactively outpace expected production growth. In this regard, we have secured near-term flow assurance and long-term out-of-basin takeaway from the Delaware Basin to the Texas Gulf Coast, with access to export markets. See Items 1. and 2. Business and Properties – US Onshore.

Colorado Proposition #112 On November 6, 2018, a majority of Colorado voters voted against Proposition #112, which, if passed, would have significantly limited, or in some cases prevented, the future development of crude oil and natural gas and demand for our midstream services in areas where we currently conduct operations.

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Initiatives have been underway in the State of Colorado to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations for some time. We are monitoring the work of the State of Colorado General Assembly to create a framework for future oil and gas development in the State. Concurrently, we are engaged in extensive public education and outreach efforts, with the goal of engaging and educating the public and communities about the economic and environmental benefits of safe and responsible crude oil and natural gas development.

Impact of Tariffs During 2018, the US Administration imposed import tariffs of 25% on steel products and 10% on aluminum products, as well as quantitative restrictions on imports of steel and/or aluminum products from various countries. 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. Implementation of these tariffs will likely increase prices for specialty and other products used in our industry. 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 pricing and production.

Recent Activities

During the period 2015-2018, we strategically repositioned our portfolio to focus capital investment primarily in US onshore plays, including the DJ and Delaware Basins and Eagle Ford Shale, and in 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.

During 2018, we continued to enhance our portfolio, concentrated development capabilities on higher-impact opportunities that can drive substantial long-term value creation, focused on margin improvements and undertook shareholder value initiatives.

We believe implementation of our focused strategy has enhanced our future outlook. During 2018, we accomplished the following:

Portfolio Activities, Including:

- sale of a 7.5% working interest in Tamar;
- sale of our 50% interest in CONE Gathering LLC and our investment in CNX Midstream Partners common units;
- sale of our Gulf of Mexico assets;
- expansion of new venture portfolio in both US onshore and international offshore locations;
- execution of numerous acreage exchanges and sales to secure more contiguous acreage positions within the DJ and Delaware Basins; and
- completing the midstream Saddle Butte Acquisition, which expanded utilization of the Advantage Pipeline.

Operational Accomplishments, Including:

- progressing Leviathan development to approximately 75% completion and remaining on budget and on schedule to flow first gas by the end of 2019;
- achieved annual average record gross sales of over 1 Bcf/d in Israel;
- advancing natural gas marketing and transportation optionality for the export of Tamar and Leviathan production to Egypt;
- progressed the next phase of development offshore West Africa by entering a Heads of Agreement establishing the framework for monetization of natural gas from the Alen field;
- increased total US onshore sales volumes by more than 18% from 2017, excluding the impact of the Marcellus Shale upstream divestiture, and continuing shift to an oilier production mix, with approximately 44% of our US onshore consolidated sales volumes attributable to crude oil;
- securing near-term flow assurance and long-term out-of-basin takeaway capacity, including the EPIC firm transport agreement, from the Delaware Basin to the Texas Gulf Coast, with access to export markets;
- expanded our midstream footprint capabilities through CGF constructions; and
- received approval for the first large-scale CDP which will span our Mustang IDP area.

Financial Initiatives, Including:

- Board of Directors authorization to implement a $750 million share repurchase program and subsequent repurchase of 10 million shares of Noble Energy common stock, for $295 million, during the year;
- increase in dividends to 11 cents per Noble Energy common share for second, third and fourth quarters and paid dividends of $208 million during 2018;

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- repayment of $609 million of outstanding debt;
- enhancement of financial flexibility via revolving credit facility maturity date extensions, a capacity increase and entry into a new term loan credit facility;
- repatriation of $791 million from foreign operations with no US tax impact;
- positive mitigation efforts for retained Marcellus Shale firm transportation contracts;
- strong liquidity position including cash on hand and unused borrowing capacity; and
- investment grade credit ratings and received improved outlooks from two agencies.

In summary, we believe our current portfolio includes assets which are well-positioned on the industry cost of supply curve, offering growth at financially attractive rates of return. Operationally, we continue to drive efficiencies in our US onshore drilling and completions, while advancing our Eastern Mediterranean and West Africa regional natural gas developments. Financially, we continue to maintain our strong balance sheet and robust liquidity position while engaging in shareholder return initiatives.

OPERATING OUTLOOK

Growing Long-Term Value We believe the following guiding principles will contribute to growing long-term value:

- Execution of a disciplined capital allocation process by:
  - designing a flexible investment program aligned with the current commodity price environment; and
  - maintaining a strong balance sheet and liquidity position.
- Enhancing capital efficiencies by:
  - utilizing our technical competencies and applying historical learnings from unconventional US shale plays to reduce US onshore finding and development costs.
- Leveraging the benefits of our well-positioned and diversified portfolio, including:
  - exercising investment optionality and flexibility afforded by our assets, certain of which are held by production; and
  - continuing portfolio optimization actions to maximize strategic value.
- Capitalizing on a currently low-cost offshore environment with execution of high-quality, long-cycle development projects, such as:
  - progressing Leviathan Phase 1 field development and monetization of natural gas offshore West Africa.
- Maintaining financial strength through:
  - focusing operational activities on high-margin, high-return assets; and
  - improving overall corporate returns.

We currently expect that commodity price improvement will be limited in the first half of 2019 and that this factor, along with the timing of our capital expenditures for US onshore development, Leviathan completion and the Aseng development well, will result in the outspending of our operating cash flows. In the second half of the year, reduced capital spend, plus the positive impact from production growth, will result in improved operating cash flows relative to capital spending.

We believe our approach positions the Company for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. Further, we expect our US onshore activity level, combined with Leviathan Phase 1 natural gas sales, expected to commence in late 2019, and our West Africa natural gas monetization strategy, which is expected to result in first gas processing in 2021, position us for robust cash flow growth in 2020-2021. However, if commodity prices are suppressed for an extended period of time and/or operating cost inflation continues impacting operating margins, 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 otherwise. Our production and our stock price could decline as a result of these potential developments. See Item 1A. Risk Factors – *The oil and gas industry is cyclical and crude oil, NGL and natural gas prices are volatile. A reduction in these prices could have a material adverse effect on our operations, our liquidity, and the price of our common stock.*

Our 2019 production target is in the range of 345 MBoe/d to 365 MBoe/d.

2019 Capital Investment Program

Exploration and Production Program Our 2019 organic 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 and acquisition capital related to the EMG Pipeline, our 2019 organic capital program is in the range of $2.4 to $2.6 billion, with approximately 70% being allocated to US onshore development and approximately 20% to complete the Leviathan project in the Eastern Mediterranean. The remaining portion of the organic capital program is designated for Noble retained Midstream activities, drilling of a crude oil development well in West Africa, and other exploration and corporate activities.

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2019 Budget Principles Our 2019 organic capital program anticipates a lower level of investment directed to our US onshore assets, as compared with 2018. We will continue to advance our US onshore program through investments in liquids-rich and high-return projects, improve execution efficiency, and enhance our midstream business value. In the Eastern Mediterranean, our 2019 organic capital program, excluding acquisition capital related to the EMG Pipeline, includes the investment needed to complete Leviathan Phase 1 development.

We will 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, NGL and natural gas production;
- operating and development costs;
- production, drilling and delivery commitments, or other contractual obligations;
- drilling results;
- cash flows from operations and 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;
- property acquisitions and divestitures;
- exploration activity; and
- potential changes in the fiscal regimes of the US and other countries in which we operate.

We plan to fund our capital investment program from cash flows from operations, cash on hand, proceeds from divestments of non-strategic assets, borrowings under our Revolving Credit Facility, and/or other sources of funding. See Liquidity and Capital Resources – Sources and Uses of Liquidity and Liquidity and Capital Resources – Contractual Obligations.

RESULTS OF OPERATIONS – E&P

Highlights for our E&P business were as follows:

2018 Significant E&P Operating Highlights Included:

- total average consolidated sales volumes of 346 MBoe/d, net;
- average daily sales volumes for US onshore crude oil of 109 MBbl/d, net; and
- average daily sales volumes of approximately 1.0 Bcfe/d, gross, offshore Israel, primarily from the Tamar field.

2018 E&P Financial Results Included:

- average realized crude oil price increase of 25% as compared with 2017;
- average realized NGL price increase of 10% as compared with 2017;
- average realized natural gas price decrease of 8% as compared with 2017;
- goodwill impairment charge of $1.3 billion attributable to the Texas reporting unit (associated with the Clayton Williams Energy Acquisition);
- pre-tax income of $119 million, as compared with pre-tax loss of $1.8 billion for 2017; and
- capital expenditures, excluding acquisitions, of $2.8 billion, as compared with $2.4 billion for 2017.

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

	Year Ended December 31,		
(millions)	2018	2017	2016
Oil, NGL and Gas Sales to Third Parties (1)	$4,461	$4,060	$3,389
Income from Equity Method Investees	132	120	50
Total Revenues	4,613	4,180	3,439
Production Expense (1)	1,358	1,270	1,200
Exploration Expense	129	188	925
Depreciation, Depletion and Amortization	1,819	1,965	2,395
Loss on Marcellus Shale Upstream Divestiture and Other	—	2,286	—

Gain on Divestitures, Net [2]	(340)	(326)	(238)
Asset Impairments [2]	169	70	92
Goodwill Impairment [3]	1,281	—	—
(Gain) Loss on Commodity Derivative Instruments	(63)	(63)	139
Clayton Williams Energy Acquisition Expenses	—	100	—
Income (Loss) Before Income Taxes	119	(1,803)	(1,271)

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(1) The adoption of ASC 606 on January 1, 2018 had a de minimis impact on revenues and production expense for 2018. See Item 8. Financial Statements and Supplementary Data – Note 4. Revenue from Contracts with Customers.

(2) See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

(3) See Item 8. Financial Statements and Supplementary Data – Note 6. Goodwill Impairment.

Average Oil, NGL and Gas Sales Volumes and Prices Average daily sales volumes and average realized sales prices 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)	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)
Year Ended December 31, 2018							
United States [2]	114	62	472	255	$61.12	$25.88	$ 2.53
Eastern Mediterranean	—	—	237	40	—	—	5.47
West Africa [3]	16	—	213	51	68.53	—	0.27
Total Consolidated Operations	130	62	922	346	62.01	25.88	2.76
Equity Investees [4]	2	5	—	7	68.99	42.14	—
Total	132	67	922	353	$62.10	$27.18	$ 2.76
Year Ended December 31, 2017							
United States	111	58	607	270	$49.11	$23.40	$ 3.02
Eastern Mediterranean	—	—	272	46	—	—	5.32
West Africa [3]	18	—	239	57	53.68	—	0.27
Total Consolidated Operations	129	58	1,118	373	49.73	23.40	3.01
Equity Investees [4]	2	6	—	8	55.13	38.48	—
Total	131	64	1,118	381	$49.84	$24.81	$ 3.01
Year Ended December 31, 2016							
United States	99	54	881	301	$39.59	$14.92	$ 2.11
Eastern Mediterranean	—	—	281	47	—	—	5.21
West Africa [3]	26	—	235	65	43.54	—	0.27
Total Consolidated Operations	125	54	1,397	413	40.39	14.92	2.42
Equity Investees [4]	2	5	—	7	45.44	26.30	—
Total	127	59	1,397	420	$40.46	$15.96	$ 2.42

(1) The adoption of ASC 606 on January 1, 2018 had a de minimis impact on revenues and production expense for 2018. See Item 8. Financial Statements and Supplementary Data – Note 4. Revenue from Contracts with Customers. Specifically, this resulted in the following:
increases in NGL revenues, and corresponding increase in production expense, of $7 million for 2018;
decreases in natural gas revenues, and corresponding decreases in production expense, of $7 million for 2018;
increases in NGL and natural gas sales volumes of 5 MBbl/d and 31MMcf/d, respectively, for 2018; and
reductions in average realized NGL and natural gas sales prices of $1.76/Bbl and $0.12/Mcf, respectively, for 2018.

(2) Includes 7 MBoe/d for 2018 related to Gulf of Mexico assets sold in April 2018. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

(3) See Items 1. and 2. Business and Properties – Delivery Commitments – West Africa Agreements.

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

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

(millions)	Crude Oil & Condensate	NGLs	Natural Gas	Total
Year Ended December 31, 2016	$ 1,854	$ 296	$ 1,239	$ 3,389
Changes due to				
Increase (Decrease) in Sales Volumes	55	17	(182)	(110)
Increase in Sales Prices [(1)]	437	180	164	781
Year Ended December 31, 2017	$ 2,346	$ 493	$ 1,221	$ 4,060
Changes due to				
Increase (Decrease) in Sales Volumes	14	—	(266)	(252)
Increase (Decrease) in Sales Prices [(1)]	585	87	(19)	653
Impact of ASC 606 Adoption	—	7	(7)	—
Year Ended December 31, 2018	$ 2,945	$ 587	$ 929	$ 4,461

(1) Changes exclude gains and losses related to commodity derivative instruments. See Item 8. Financial Statements and Supplementary Data – Note 13. Derivative Instruments and Hedging Activities.

Crude Oil and Condensate Sales Revenues Revenues from crude oil and condensate sales increased in 2018 as compared with 2017 due to the following:

- 25% increase in average realized prices (see factors impacting global pricing at Executive Overview - Industry Outlook); and
- higher US onshore sales volumes of 19 MBbl/d primarily driven by an increase in development activity in the Delaware and DJ Basins;

partially offset by:

- lower Gulf of Mexico sales volumes of 16 MBbl/d resulting from the sale of the Gulf of Mexico assets in second quarter 2018; and
- lower offshore West Africa sales volumes of 2 MBbl/d resulting from natural field decline.

Revenues from crude oil and condensate sales increased in 2017 as compared with 2016 due to the following:

- 23% increase in average realized prices (see factors impacting global pricing at Executive Overview – Industry Outlook);
- higher US onshore sales volumes of 16 MBbl/d, including 5 MBbl/d contributed by Clayton Williams Energy assets, primarily attributable to increased development and enhanced well design and completion techniques; and
- higher sales volumes of 2 MBbl/d due to full year of production at Gunflint, a Gulf of Mexico project that started production in July 2016;

partially offset by:

- lower sales volumes of 14 MBbl/d primarily due to natural field decline in the Gulf of Mexico and Equatorial Guinea.

NGL Sales Revenues Revenues from NGL sales increased in 2018 as compared with 2017 due to the following:

- higher US onshore sales volumes of 6 MBbl/d (exclusive of 5 MBbl/d from adoption of ASC 606) primarily attributable to development activities in the Delaware and DJ Basins;
- 10% increase in average realized prices (see factors impacting global pricing at Executive Overview – Industry Outlook); and
- $7 million increase associated with the adoption of ASC 606;

partially offset by:

- lower sales volumes of 5 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Revenues from NGL sales increased in 2017 as compared with 2016 due to the following:

- 56% increase in average realized prices (see factors impacting global pricing at Executive Overview – Industry Outlook); and
- higher US onshore sales volumes of 7 MBbl/d, including 1 MBbl/d contributed by Clayton Williams Energy assets, primarily attributable to increased development and enhanced well design and completion techniques;

partially offset by:

- lower sales volumes of 4 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Natural Gas Sales Revenues Revenues from natural gas sales decreased in 2018 as compared with 2017 due to the following:

- lower sales volumes of 174 MMcf/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;

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- lower Gulf of Mexico sales volumes of 14 MMcf/d resulting from the sale of the Gulf of Mexico assets in second quarter 2018;
- lower Israel sales volumes of 35 MMcf/d due to the sale of a 7.5% interest in the Tamar field in second quarter 2018;
- $7 million decrease associated with the adoption of ASC 606;
- lower sales volumes of 26 MMcf/d from the Alba field, offshore Equatorial Guinea, resulting from natural field decline and timing of field maintenance; and
- 8% decrease in average realized prices primarily due to the impact of increased US onshore supply;

partially offset by:

- higher US onshore sales volumes of 30 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606) primarily attributable to development activities in the Delaware and DJ Basins; and
- higher sales volumes related to our remaining working interest in Israel due to increased demand for power as well as conversion of facilities from use of coal to natural gas.

Revenues from natural gas sales decreased slightly in 2017 as compared with 2016 due to the following:

- lower sales volumes of 312 MMcf/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017; and
- lower sales volumes of 29 MMcf/d as a result of the sale of a 3.5% working interest in the Tamar field in December 2016, partially offset by higher gross sales volumes from the field;

partially offset by:

- 24% increase in average realized prices (see factors impacting global pricing at Executive Overview – Industry Outlook); and
- higher US onshore sales volumes of 40 MMcf/d, including 6 MMcf/d contributed by Clayton Williams Energy assets.

Income from Equity Method Investees Our share of operations of equity method investees were as follows:

	Year Ended December 31,		
	2018	2017	2016
Net Income (in millions)			
AMPCO and Affiliates	$64	$58	$16
Alba Plant	71	65	34
Dividends (in millions)			
AMPCO and Affiliates	$63	$47	$16
Alba Plant	93	68	40
Sales Volumes			
Methanol (MMgal)	149	163	162
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	6	5
Average Realized Prices			
Methanol (per gallon)	$1.14	$0.97	$0.63
Condensate (per Bbl)	68.99	55.13	45.44
LPG (per Bbl)	42.14	38.48	26.30

Changes for 2018 as compared with 2017 included the following:

- increase in net income from AMPCO and affiliates primarily due to higher realized methanol prices; and
- increase in net income from Alba Plant primarily due to higher realized LPG prices.

Changes for 2017 as compared with 2016 included the following:

- increase in net income from AMPCO and affiliates primarily due to higher realized methanol prices; and
-

increase in net income from Alba Plant primarily due to higher LPG sales volumes and realized prices.

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Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)(2)	Total	United States (2)	Eastern Mediterranean	West Africa
Year Ended December 31, 2018					
Lease Operating Expense (3)	$4.78	$603	$480	$ 26	$ 97
Production and Ad Valorem Taxes	1.46	184	184	—	—
Gathering, Transportation and Processing (4)	4.22	533	533	—	—
Other Royalty Expense	0.30	38	38	—	—
Total Production Expense	$10.76	$1,358	$1,235	$ 26	$ 97
Total Production Expense per BOE		$10.76	$13.28	$ 1.79	$ 5.20
Year Ended December 31, 2017					
Lease Operating Expense (3)	$4.29	$585	$466	$ 29	$ 90
Production and Ad Valorem Taxes	0.84	115	115	—	—
Gathering, Transportation and Processing	4.04	550	550	—	—
Other Royalty Expense	0.15	20	20	—	—
Total Production Expense	$9.32	$1,270	$1,151	$ 29	$ 90
Total Production Expense per BOE		$9.32	$11.68	$ 1.74	$ 4.28
Year Ended December 31, 2016					
Lease Operating Expense (3)	$3.72	$560	$418	$ 37	$ 105
Production and Ad Valorem Taxes	0.36	55	55	—	—
Gathering, Transportation and Processing	3.73	564	564	—	—
Other Royalty Expense	0.14	21	21	—	—
Total Production Expense	$7.95	$1,200	$1,058	$ 37	$ 105
Total Production Expense per BOE		$7.95	$9.63	$ 2.14	$ 4.42

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

(2) US production expense includes charges from our midstream operations that are eliminated on a consolidated basis. See Item 8. Financial Statements and Supplementary Data – Note 3. 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) The adoption of ASC 606 on January 1, 2018 had a de minimis impact on revenues and production expense for 2018. See Item 8. Financial Statements and Supplementary Data – Note 4. Revenue from Contracts with Customers.

Lease Operating Expense Lease operating expense increased in 2018 as compared with 2017 primarily due to the following:

- increase of $93 million primarily due to increased development activities resulting in added production in the DJ and Delaware Basins; and
- increase in costs in the Delaware Basin due to higher activity and demand for supplies and services, particularly water disposal;

partially offset by:

- decrease of $84 million due to lower production in the Gulf of Mexico resulting from natural field decline and the subsequent sale of the assets in second quarter 2018; and
- decrease of $13 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Lease operating expense increased in 2017 as compared with 2016 primarily due to the following:

- increase of $82 million in US onshore, primarily in the DJ Basin, Delaware Basin and Eagle Ford Shale due to increased activity;

partially offset by:

- decrease of $19 million resulting from natural field decline in the Gulf of Mexico;

- decrease of $17 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;
- decrease of $15 million due to various cost reduction initiatives offshore West Africa; and
- decrease of $11 million due to a 3.5% lower working interest in the Tamar field following the partial divestiture in December 2016.

Production and Ad Valorem Tax Expense Production and ad valorem taxes increased in 2018 as compared with 2017, primarily due to higher commodity prices.

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Production and ad valorem taxes increased in 2017 as compared with 2016, primarily due to higher commodity prices and a $28 million US onshore severance tax refund recorded in first quarter 2016 versus a $7 million US onshore severance tax charge recorded in first quarter 2017.

Gathering, Transportation and Processing Expense Gathering, transportation and processing expense decreased in 2018 as compared with 2017 primarily due to:

- decrease of $17 million in the Gulf of Mexico due to lower production resulting from natural field decline and the subsequent sale of the assets in second quarter 2018; and
- decrease of $88 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;

partially offset by:

- increase of $63 million related to increased activity in Delaware and DJ Basins.

Gathering, transportation and processing expense remained relatively flat in 2017 as compared with 2016 primarily due to:

- decrease of $120 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;

partially offset by:

- increase of $57 million in the DJ Basin due to the shifting of crude oil volumes onto a new export pipeline and contractual increases of pipeline fees; and
- increase of $47 million related to higher production in the Delaware Basin and Eagle Ford Shale.

Other Royalty Expense Other royalty expense increased in 2018 as compared with 2017, primarily due to higher commodity prices. Other royalty expense remained relatively flat in 2017 as compared with 2016.

Unit Rate Per BOE Production expense on a per BOE basis increased in 2018 as compared with 2017, primarily due to the decrease in total sales volumes driven by divestitures of the Marcellus Shale upstream assets in second quarter 2017 and Gulf of Mexico assets in second quarter 2018, which lowered our average production expense per BOE. These impacts were offset by an increase in volumes from the higher cost Delaware Basin.

Production expense on a per BOE basis increased in 2017 as compared with 2016, primarily due to the increases in certain production expenses noted above. In addition, the Marcellus Shale upstream divestiture resulted in the removal of lower-cost, natural gas-focused sales volumes from our portfolio, while an increase in Delaware Basin and Eagle Ford Shale volumes contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE. Also, higher commodity prices led to higher production and ad valorem taxes per BOE.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	Eastern Mediter-ranean	West Africa	Other Int'l
Year Ended December 31, 2018					
Leasehold Impairment and Amortization	$1	$1	$ —	$ —	$—
Dry Hole Cost (1)	1	1	—	—	—
Seismic, Geological and Geophysical	22	8	3	—	11
Staff Expense	54	41	2	5	6
Other (2)	51	(3)	2	1	51
Total Exploration Expense	$129	$48	$ 7	$ 6	$68
Year Ended December 31, 2017					
Leasehold Impairment and Amortization	$62	$60	$ —	$ —	$2
Dry Hole Cost (1)	9	—	—	—	9
Seismic, Geological and Geophysical	27	8	—	—	19
Staff Expense	55	1	2	4	48
Other (2)	35	33	—	1	1
Total Exploration Expense	$188	$102	$ 2	$ 5	$79
Year Ended December 31, 2016					
Leasehold Impairment and Amortization	$148	$123	$ —	$ —	$25
Dry Hole Cost (1)	579	85	26	468	—

Seismic, Geological and Geophysical	76	—	—	10	66
Staff Expense	77	3	1	5	68
Other [2]	45	34	7	—	4
Total Exploration Expense	$925	$245	$ 34	$ 483	$163

[1] See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

(2) Includes lease rental and other exploration expense.

Exploration expense for 2018 included:

- staff expense incurred across our US onshore assets.

Exploration expense for 2017 included:

- leasehold impairment expense related primarily to Gulf of Mexico unproved properties; and
- dry hole cost of $7 million for the Araku-1 exploration well, offshore Suriname.

Exploration expense for 2016 included:

- leasehold impairment expense, including the write-off of leases and licenses, of $58 million for the Gulf of Mexico, $25 million for other international locations, and $10 million for other US onshore; and
- dry hole cost including costs related to the Silvergate exploratory well, Gulf of Mexico, the Dolphin 1 natural gas discovery, offshore Israel, and certain discoveries offshore West Africa.

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

(millions, except unit rate)	Total	United States	Eastern Mediter-ranean	West Africa	Other Int'l
Year Ended December 31, 2018					
DD&A Expense	$1,819	$1,642	$ 60	$ 115	$ 2
Unit Rate per BOE (1)	$14.42	$17.66	$ 4.13	$ 6.17	$ —
Year Ended December 31, 2017					
DD&A Expense	$1,965	$1,739	$ 76	$ 146	$ 4
Unit Rate per BOE (1)	$14.42	$17.65	$ 4.56	$ 6.95	$ —
Year Ended December 31, 2016					
DD&A Expense	$2,395	$2,103	$ 81	$ 205	$ 6
Unit Rate per BOE (1)	$15.87	$19.14	$ 4.69	$ 8.63	$ —

(1) DD&A expense includes accretion of discount on AROs of $33 million in 2018, $47 million in 2017, and $48 million in 2016.

Total DD&A expense decreased in 2018 as compared with 2017 primarily due to the following:

- decrease of $223 million due to both lower sales volumes in the Gulf of Mexico resulting from natural field decline and classification of the assets as held for sale in first quarter 2018, resulting in the cessation of DD&A expense;
- decrease of $15 million due to reclassification of a 7.5% working interest in the Tamar field as assets held for sale at December 31, 2017, resulting in cessation of DD&A expense; and
- decrease of $90 million due to the Marcellus Shale upstream divestiture in second quarter 2017;

partially offset by:

- higher sales volumes in the Delaware Basin, which almost doubled, due to increased development activities subsequent to the Clayton Williams Energy Acquisition in second quarter 2017.

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

Total DD&A expense decreased in 2017 as compared with 2016 primarily 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 and globally due to positive price revisions;
- lower sales volumes in the DJ Basin and the impact of certain property divestitures since the second quarter 2016;
- decrease of $291 million due to the Marcellus Shale upstream divestiture in second quarter 2017;
- decrease of $7 million due to the sale of a 3.5% working interest in the Tamar field in December 2016;

- decrease of $37 million due to a reduction in depletable costs of $153 million due to the reallocation of common asset costs from the Alen field, offshore Equatorial Guinea, to the West Africa natural gas monetization development project in second quarter 2017; and
- lower sales volumes in the Gulf of Mexico resulting from natural field decline and reduction in the depletable costs due to downward revisions in estimates of ARO costs;

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partially offset by:

- higher US onshore sales volumes of 29 MBoe/d, including 7 MBoe/d contributed by Clayton Williams Energy assets;
- increase in sales volumes from the Gunflint development, Gulf of Mexico, which commenced production in July 2016; and
- higher gross sales volumes from the Tamar field due to higher domestic demand.

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

Gain on Divestitures, Net See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Goodwill Impairment See Critical Accounting Policies and Estimates – Goodwill and Item 8. Financial Statements and Supplementary Data – Note 6. Goodwill Impairment.

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

For 2018, gain on commodity derivative instruments included:

- net cash settlement payment of $161 million; and
- net non-cash increase of $224 million in the fair value of our net commodity derivative asset, primarily driven by decreases in the forward commodity price curve for crude oil.

For 2017, gain on commodity derivative instruments included:

- net cash settlement receipt of $13 million; and
- net non-cash increase of $50 million in the fair value of our net commodity derivative liability, primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

For 2016, loss on commodity derivative instruments included:

- net cash settlement receipt of $569 million; and
- net non-cash decrease of $708 million in the fair value of our net commodity derivative liability, primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

See Item 8. Financial Statements and Supplementary Data – Note 13. Derivative Instruments and Hedging Activities.

RESULTS OF OPERATIONS – MIDSTREAM

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

Results of Operations

Highlights for the Midstream segment were as follows:

2018 Significant Midstream Operating Highlights Included:

- completed the Saddle Butte Acquisition;
- completed construction of the Coronado, Collier and Billy Miner Train II CGFs in the Delaware Basin;
- completed construction of freshwater delivery infrastructure and commenced gathering services in the DJ Basin;
- signed a non-binding letter of intent with Salt Creek for construction of a crude oil pipeline system in the Delaware Basin, for which definitive agreements with Salt Creek were executed in February 2019;
- commenced natural gas compression in the Delaware Basin; and
- in first quarter 2019, exercised options to acquire equity interests in the EPIC Y-Grade Pipeline and the EPIC Crude Oil Pipeline.

2018 Midstream Financial Results Included:

- pre-tax income of $726 million, as compared with pre-tax income of $233 million for 2017;

- net proceeds of approximately $696 million received, and gain of $503 million recognized, on the sale of our interest in CONE Gathering and sale of our investment in CNX Midstream Partners common units; and
- capital expenditures, excluding acquisitions, of $521 million, as compared with $399 million for 2017.

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

	Year Ended December 31,		
(millions)	2018	2017	2016
Midstream Services Revenues – Third Party	$ 78	$ 19	$ —
Sales of Purchased Oil	142	—	—
Income from Equity Method Investees	40	57	52
Intersegment Revenues	351	277	200
Total Revenues	611	353	252
Operating Costs and Expenses	128	90	57
Depreciation, Depletion and Amortization	87	30	19
Gain on Divestiture, Net	(503)	—	—
Asset Impairments	37	—	—
Cost of Purchased Oil	136	—	—
Total (Income) Expense	(115)	120	76
Income Before Income Taxes	726	233	176

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

Total revenues for 2018 increased from 2017 primarily due to an increase in crude oil, produced water and natural gas gathering services and fresh water delivery revenues due to the commencement of services in the Greeley Crescent IDP area of the DJ Basin and the Delaware Basin. In addition, in first quarter 2018, Noble Midstream Partners acquired an interest in Black Diamond which completed the Saddle Butte Acquisition of a large-scale integrated gathering system and associated third-party contracts which include transactions for the purchase and sale of crude oil with varying counterparties. The purchases and sales of crude oil are at the prevailing market prices.

Total revenues for 2017 increased from 2016 primarily due to increases of $60 million and $17 million driven by our drilling and completion activities in the DJ and Delaware Basins, respectively, and an increase of $19 million primarily due to commencement of services in the DJ Basin to an unaffiliated third-party.

Income from Equity Method Investees Midstream's share of operations of equity method investees was as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Net Income			
CONE Gathering and CONE Midstream [1]	$ 24	$ 51	$ 48
Advantage Pipeline	12	2	—
Other	4	4	5
Dividends			
CONE Gathering and CONE Midstream [1]	19	25	27
Advantage Pipeline	9	—	—

(1) Investments were sold in separate transactions in 2018. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Operating Costs and Expenses

Total expense for 2018 increased by $38 million as compared with 2017 due to the following:

- increase of $21 million due to the addition of expenses associated with the Black Diamond gathering system acquired in the Saddle Butte Acquisition in first quarter 2018;

- increase of $12 million in gathering, transportation and processing expense associated with the new CGFs in the Delaware Basin and commencement of gathering services in the Mustang IDP area of the DJ Basin.

Total expense for 2017 increased by $33 million as compared with 2016 due to the following:

- increase of $20 million in water services expense due to increased services provided by third parties as well as higher throughput volumes associated with fresh water services;
- increase of $6 million in gathering and facilities operating expense due to higher gathered volumes, as well as due to new systems placed in service and expansion of the gathering infrastructure in 2017; and

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- increase of $7 million in general and administrative and other expenses, primarily related to increased third-party legal and advisory fees resulting from transactions.

DD&A Expense DD&A expense for 2018 increased by $57 million as compared with 2017 primarily due to tangible assets acquired in the Saddle Butte Acquisition, assets placed in service in 2018, specifically the CGFs in the Delaware Basin and gathering system in the DJ Basin, and an increase of $30 million related to amortization of customer-related intangible assets acquired in the Saddle Butte Acquisition.

DD&A expense for 2017 increased by $11 million as compared with 2016 primarily due to the assets placed in service in 2017, specifically assets associated with the construction of the Greeley Crescent facilities and the Delaware Basin gathering systems, including completion of two CGFs, and expansion of gathering and fresh water systems in the Wells Ranch, East Pony and Mustang IDP areas.

Gain on Divestitures, Net Gain on divestitures, net, includes the first quarter 2018 sale of our interest in CONE Gathering and second and third quarter 2018 sales of our investment in CNX Midstream Partners common units. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Salt Creek Joint Venture In October 2018, Noble Midstream Partners entered into a non-binding letter of intent with Salt Creek to form a 50/50 joint venture to construct a 160 MBbl/d day crude oil pipeline system in the Delaware Basin. On February 7, 2019, Noble Midstream Partners executed definitive agreements and completed the formation of Delaware Crossing.

The 95-mile pipeline system will originate in Pecos County, Texas, with additional connections in Reeves County and Winkler County, Texas. The project footprint will be served by a combination of in-field crude oil gathering lines and a trunkline to a hub in Wink, Texas. The project is underpinned by approximately 192,000 dedicated gross acres and nearly 100 miles of gathering pipeline in Pecos, Reeves, Ward and Winkler Counties, Texas. The pipeline is expected to be operational in second quarter 2019.

RESULTS OF OPERATIONS – CORPORATE

Our Corporate costs include exit and certain costs associated with mitigating the effects of our retained Marcellus Shale firm transportation agreements and expenses related to debt, headquarters depreciation, and corporate general and administrative expenses.

Marcellus Shale Firm Transportation Contracts Revenues and expenses associated with retained Marcellus Shale firm transportation contracts were as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Sales of Purchased Gas	$113	$ —	$ —
Loss on Marcellus Shale Upstream Divestiture and Other [1]	—	(93)	—
Cost of Purchased Gas	(140)	—	—

[1] Represents accrued non-cash exit costs related to certain retained Marcellus Shale firm transportation contracts.

See Item 8. Financial Statements and Supplementary Data – Note 10. Marcellus Shale Firm Transportation Contracts.

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

	Year Ended December 31,		
(millions, except unit rate)	2018	2017	2016
G&A Expense	$385	$415	$399
Unit Rate per BOE [1]	$3.05	$3.05	$2.64

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

On a gross basis, G&A expense for 2018 increased as compared with 2017 primarily due to increased employee overhead related costs and campaign and government relations costs related to Colorado Proposition #112. On a net basis, G&A expense for 2018 decreased as compared with 2017 due to enhanced recovery of overhead costs. The unit rate per BOE was flat as compared with 2017.

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G&A expense for 2017 increased slightly as compared with 2016 primarily due to increased employee costs driven by acquisition activities. The increase in the unit rate per BOE for 2017 as compared with 2016 was due primarily to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets.
G&A expense is impacted by the number of stock-based awards, the market price of our common stock and price volatility which may result in a higher or lower fair value of stock-based awards as calculated using various valuation models. G&A expense included stock-based compensation expense of $54 million in 2018, $56 million in 2017 and $62 million in 2016. See Item 8. Financial Statements and Supplementary Data – Note 17. Stock-Based and Other Compensation Plans.
Loss (Gain) on Extinguishment of Facility or Debt See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.
Other Operating Expense, Net See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.
Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

	Year Ended December 31,		
(millions, except unit rate)	2018	2017	2016
Interest Expense	$355	$403	$412
Capitalized Interest	(73)	(49)	(84)
Interest Expense, Net	$282	$354	$328
Unit Rate per BOE [(1)]	$2.23	$2.60	$2.17

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

Interest expense for 2018 decreased as compared with 2017 primarily due to a decrease in the overall debt balance. In fourth quarter 2017, we repaid our former $550 million Term Loan Facility due January 6, 2019. In 2018, we repaid $379 million of Senior Notes due May 1, 2021 and $230 million, net, on our Revolving Credit Facility. In addition, in third quarter 2017, we conducted a tender offer and refinanced our 8.25% Senior Notes, resulting in a lower interest rate and lower interest expense, gross, for 2018 as compared with 2017. These financing activities were partially offset by an increase in Noble Midstream Partners debt of $475 million, which was primarily used to fund the first quarter 2018 Saddle Butte Acquisition.
Capitalized interest for 2018 increased as compared with 2017 primarily due to higher work in progress amounts related to Leviathan development.
Interest expense for 2017 decreased as compared with 2016 primarily due to the third quarter 2017 refinancing of our 8.25% senior notes and fourth quarter 2017 repayment of our Term Loan Facility due January 6, 2019.
Capitalized interest for 2017 decreased as compared with 2016 primarily due to the write off of discoveries offshore Equatorial Guinea, lower work in progress amounts related to major long-term projects, including Gunflint, Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, partially offset by a higher work in progress amount related to the Leviathan development project.
Interest is capitalized on exploration and development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest is related to long lead-time projects in offshore West Africa and offshore Eastern Mediterranean. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.
Income Taxes See Item 8. Financial Statements and Supplementary Data – Note 12. Income Taxes.

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 commodity price cycles, 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 liquidity are cash flows from operations, cash on hand, proceeds from divestitures of properties and other investments, and available borrowing capacity under our $4.0 billion unsecured Revolving Credit Facility. 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

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maturities. In 2019, we put in place a $4.0 billion commercial paper program to provide for short-term funding needs. 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. We also enter into crude oil and natural gas price hedging arrangements in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil and natural gas production.

Our portfolio transformation strategy, primarily executed during 2017, 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, our investment in CNX Midstream Partners common units, and other US onshore assets. As a result, our divestitures generated cash proceeds of approximately $2.0 billion and $2.1 billion in 2018 and 2017, respectively, which were used to improve our capital structure, fund a portion of our capital program, strengthen our liquidity and return value to shareholders through the share repurchase program.

In 2018, we funded our capital program through organic cash flows, proceeds from divestitures and, when needed, borrowings under our Revolving Credit Facility. During the year, we borrowed and repaid amounts under our Revolving Credit Facility, resulting in no amounts outstanding as of December 31, 2018. As a result of our financing activities, we ended 2018 with over $4.7 billion in liquidity, including $4.0 billion of availability under our Revolving Credit Facility.

As of December 31, 2018, our outstanding long-term debt, net of unamortized discount and debt issuance costs and excluding capital lease obligations, totaled $6.4 billion. We may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness. In addition, we may from time to time seek to retire or purchase our outstanding senior notes through cash purchases in the open market, privately negotiated transactions or otherwise. Such activities, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

Sources and Uses of Liquidity

Our operating cash flows are a significant source of liquidity. For most of 2018, we experienced strengthening crude oil and NGL prices and completed several divestitures which continued the transformation strategy started in 2017, repositioning our US portfolio to high margin onshore crude oil-rich assets. These activities significantly contributed to the funding of our capital program. Additional sources of funding were available through debt financing activities, including borrowings under our Revolving Credit Facility. At the same time, we focused efforts on shareholder return initiatives, including share repurchases and dividends. Additionally, we redeemed $379 million in outstanding senior notes and repaid $230 million of outstanding 2017 borrowings on our Revolving Credit Facility.

Overall, we expect to support our 2019 capital investment program with cash flows from operations, cash on hand, proceeds from divestments of non-strategic assets, issuances of commercial paper, borrowings under our Revolving Credit Facility, and/or other sources of funding.

We believe our current liquidity level and balance sheet, along with our ability to access the capital markets, provide flexibility and that we are well-positioned to fund our business throughout the commodity price cycle. We will continue to evaluate the commodity price environment and our level of capital spending throughout 2019. A downgrade below our current investment grade rating could trigger requirements to post collateral as financial assurance of performance under certain contractual arrangements. See Item 1A. Risk Factors – *Indebtedness may limit our liquidity and financial flexibility.*

The table below summarizes our cash, debt balances and available liquidity:

	December 31,		
(millions, except percentages)	2018	2017	2016
Total Cash (1)	$719	$713	$1,210
Amount Available to be Borrowed under Revolving Credit Facility (2)	4,000	3,770	4,000
Total Liquidity	$4,719	$4,483	$5,210
Total Debt (3)	$6,675	$6,859	$7,114
Noble Energy Share of Equity	10,484	10,619	9,600

Ratio of Debt-to-Book Capital [4]	39 %	39 %	43 %

(1) As of December 31, 2018, total cash includes cash and cash equivalents of $11 million related to Noble Midstream Partners and $3 million of restricted cash related to amounts held for the divestiture of certain non-core acreage in the Delaware Basin and Noble Midstream Partners collateral on letters of credit. As of December 31, 2017, total cash includes $18 million cash of Noble Midstream Partners and $38 million of restricted cash related to the Saddle Butte Acquisition that closed first quarter 2018. As of December 31, 2016, total cash includes $57 million cash of Noble Midstream Partners, and restricted cash of $30 million related to the Delaware Basin property acquisition that closed in January 2017.

(2) Excludes amounts available to be borrowed under the Noble Midstream Services Revolving Credit Facility, which is not available to Noble Energy for general corporate purposes.

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(3) Total debt includes capital lease obligations and excludes unamortized debt discount/premium and debt issuance costs. Additionally, it includes $560 million of Noble Midstream Partners debt as of December 31, 2018.

(4) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount/premium and issuance costs, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus Noble Energy's share of equity.

Cash and Cash Equivalents We had approximately $716 million in cash and cash equivalents at December 31, 2018, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $456 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 and the Noble Midstream Services Revolving Credit Facility of $800 million both mature in 2023. These facilities are used to fund capital investment programs and acquisitions and may periodically provide amounts for working capital purposes. At December 31, 2018, no amounts were outstanding under the Revolving Credit Facility and $60 million was outstanding under the Noble Midstream Services Revolving Credit Facility, leaving $4.0 billion and $740 million in remaining availability under the respective credit facilities. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

Commercial Paper Program In 2019, we established a commercial paper program, which allows for a maximum of $4.0 billion of unsecured commercial paper notes and is supported by Noble Energy’s Revolving Credit Facility, to provide for short-term funding needs. Commercial paper generally has a maturity of between 1 and 90 days, although it can have a maturity of up to 397 days. The commercial paper is sold under customary terms in the commercial paper market and notes either are issued at a discount price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted prices or interest amounts are dependent on market conditions and ratings assigned to the commercial paper program by the credit agencies at the time of issuance of the commercial paper.

Noble Midstream Services Term Loan Credit Facility In July 2018, Noble Midstream Services entered into the Noble Midstream Services Term Loan Credit Facility that permits aggregate borrowings of up to $500 million. As of December 31, 2018, $500 million was outstanding under this facility, which was used to repay amounts outstanding under the Noble Midstream Services Revolving Credit Facility. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

Leviathan Term Loan Facility The facility, which provided for a limited recourse secured loan facility with an aggregate principal borrowing amount of up to $1.0 billion, of which $625 million was initially committed, was terminated in December 2018. No amounts were ever drawn on 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 our acquisition of Rosetta Resources, for $395 million.

Cash Flows

The following table summarizes our net cash flows from operating, investing and financing activities:

	Year Ended December 31,		
(millions)	2018	2017	2016
Total Cash Provided By (Used in)			
Operating Activities	$2,336	$1,951	$1,351
Investing Activities	(1,931)	(1,617)	(401)
Financing Activities	(399)	(831)	(768)
Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	$6	$(497)	$182

Operating Activities In 2018, net cash provided by operating activities increased as compared with 2017, primarily resulting from an increase in net revenues due to rising crude oil and NGL commodity prices, partially offset by higher production costs attributable to increased operational activity and rising costs in US onshore, and a decrease in US natural gas sales volumes. In addition, we made cash settlements of $161 million for commodity derivatives, as compared with cash receipts of $13 million in the prior year and cash interest payments related to outstanding debt of $343 million as compared with $394 million in 2017.

Working capital changes resulted in a $47 million operating cash flow decrease in 2018 as compared with a $150 million operating cash flow decrease in 2017. The changes in working capital were primarily due to an increase in our trade payables for drilling and development costs and midstream capital expenditures and decrease in accounts receivable. The increase was partially offset by the increase in non-current assets, specifically the customer-related intangible asset recorded as part of the Saddle Butte Acquisition in first quarter 2018.

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In 2017, net cash provided by operating activities increased as compared with 2016. The change in cash flows from operating activities was primarily the result of higher average realized commodity prices partially offset by lower sales volumes as a result of the Marcellus Shale upstream divestiture and lower settlements of commodity derivative instruments. The increase in cash flows from sales was offset by the decrease in settlement proceeds from our commodity derivative instruments. The decrease in cash received from derivative settlements is reflective of an increase in the commodity prices as crude oil and natural gas prices strengthened in the second half of 2017. In 2017, we made cash interest payments related to outstanding debt of $394 million as compared with $412 million in 2016.

Investing Activities In 2018, capital spending for additions to property, plant and equipment, excluding acquisitions, totaled $3.3 billion as compared with $2.6 billion in 2017. The increase was primarily due to increased development spending for the Delaware Basin, Leviathan Phase 1 and midstream infrastructure. This was partially offset by decreased development spending in the Eagle Ford Shale and on the Marcellus Shale upstream assets and Gulf of Mexico assets following their respective sales. In addition, $653 million was spent on acquisitions during 2018.

During 2018, we received net cash proceeds of $2.0 billion from divestitures. We utilized sales proceeds to support our development activities in core operational areas, redeem senior note balances and further strengthen our liquidity position. See Item 8. Financial Statements and Supplementary Data – Note 5. Acquisitions and Divestitures.

Capital expenditures in 2017 were $2.6 billion, or $1.1 billion higher than capital spent in 2016. Approximately $700 million of the increase was due to increased US onshore development activity in response to a more favorable commodity price environment, as well as our focus on development of high margin areas in the DJ and Delaware Basins, and approximately $416 million of the increase was related to the initial Leviathan project development.

In 2016, capital spending for property, plant and equipment was $1.5 billion, or nearly half of capital spent in 2015, due to the timing of completion of major project development activities in the Gulf of Mexico, DJ Basin and Marcellus Shale. We received $1.2 billion of proceeds from asset divestitures, as compared with $151 million of proceeds from divestitures during 2015.

Financing Activities In 2018, our primary financing activities included a $230 million, net, Revolving Credit Facility repayment and a $25 million, net, Noble Midstream Services Revolving Credit Facility repayment, which included borrowings of $475 million primarily used to fund an acquisition, offset by a repayment of $500 million drawn under the Noble Midstream Services Term Loan Credit Facility. We also used $384 million of cash to redeem senior notes, for which payment of accrued interest of $11 million is reflected in operating activities.

In addition, we used cash of $295 million pursuant to our share repurchase program and paid $208 million of cash dividends to Noble Energy shareholders and $51 million of cash distributions to Noble Midstream Partners noncontrolling interest owners. We also received $353 million of contributions from noncontrolling interest owners. Other financing activities used net cash of $110 million.

In 2017, our primary financing activities included $230 million net Revolving Credit Facility borrowings (including the borrowing and repayment of $1.3 billion associated with the Clayton Williams Energy Acquisition), $85 million, net, Noble Midstream Services Revolving Credit Facility borrowings used primarily to fund an acquisition, a $1.1 billion senior note refinancing, $595 million related to the repayment of Clayton Williams Energy debt, and a $550 million Term Loan Facility repayment. In addition, we received $312 million net proceeds from the issuance of Noble Midstream Partners common units, paid $190 million of cash dividends and $28 million of cash distributions, and made $60 million of capital lease principal payments.

We also received $10 million cash proceeds from the exercise of stock options and purchased 1,031,000 shares of treasury stock with a value of $36 million. These shares included 719,849 shares with a value of $25 million related to vesting of Clayton Williams Energy restricted stock and options in connection with the Clayton Williams Energy Acquisition. The remaining shares were surrendered for the payment of withholding taxes due on the vesting of employee restricted stock awards.

In 2016, we used Term Loan Facility proceeds of $1.4 billion to redeem $1.4 billion of senior notes. We subsequently repaid $850 million of the Term Loan Facility from cash on hand. We received $299 million net proceeds from the issuance of Noble Midstream Partners common units in a public offering. We also used cash to pay dividends on our common stock of $172 million. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows.

Acquisition, Capital Expenditures and Other Exploration Expenditures

Our capital expenditures (on an accrual basis) were as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition [(1)]	$41	$1,817	$234
Proved Property Acquisition [(2)]	—	839	—
Exploration and Development	2,683	2,352	1,239
Midstream [(3)]	727	480	42
Corporate	60	34	50
Total	$3,511	$5,522	$1,565
Other			
Investment in Equity Method Investee [(4)]	$—	$68	$8
Increase in Capital Lease Obligations	14	—	5

(1) 2018 costs relate to US onshore undeveloped leasehold activity.
2017 costs include $1.6 billion related to the Clayton Williams Energy Acquisition and $246 million related to acquisitions in the Delaware Basin.
2016 costs relate to properties exchanged upon termination of the Marcellus Shale joint development agreement.

(2) 2017 costs include $722 million of proved properties and $63 million of ARO acquired in the Clayton Williams Energy Acquisition and $58 million of proved properties acquired in the Delaware Basin.

(3) Midstream expenditures include those of Noble Midstream Partners.
2018 includes $206 million related to the Saddle Butte Acquisition.
2017 includes gathering and processing assets of $48 million related to the Clayton Williams Energy Acquisition.

(4) 2017 includes our contribution to the Advantage Pipeline joint venture, in which Noble Midstream Partners owns a 50% interest.

Exploration and development costs increased in 2018 as compared with 2017, primarily due to increased US onshore and Leviathan development activities. Exploration and development costs include approximately $2.0 billion for US onshore and approximately $676 million for Eastern Mediterranean activities primarily related to Leviathan. In addition, Midstream capital spending, exclusive of acquisitions, increased in 2018 due to the construction of gathering systems in the DJ and Delaware Basins.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2018, material off-balance sheet arrangements and transactions that we have entered into included drilling rig contracts, transportation and gathering agreements, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry (see cross references to the Notes to the Financial Statements in the table below). Other than these aforementioned arrangements, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our financial condition, results of operations, liquidity or availability of or requirements for capital resources. See *Contractual Obligations,* below.

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Contractual Obligations

The following table summarizes certain contractual obligations as of December 31, 2018 that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. Unless otherwise noted, all amounts are undiscounted and are net to our interest.

(millions)	Note Reference (1)	Total	2019	2020 and 2021	2022 and 2023	2024 and beyond
Long-Term Debt (2)	Note 9	$6,452	$—	$1,500	$160	$4,792
Interest Payments (3)	Note 9	5,490	295	589	505	4,101
Capital Lease Obligations (4)	Note 9	275	52	77	42	104
Purchase and Service Obligations (5)	Note 11	271	197	42	27	5
Marcellus Shale Firm Transportation and Other Obligations (6)	Note 10	1,531	123	243	231	934
Gathering, Transportation and Processing Obligations	Note 11	801	151	232	133	285
Operating Lease Obligations (7)	Note 11	512	91	133	112	176
Other Liabilities (8)						
Asset Retirement Obligations (9)	Note 8	880	118	147	67	548
Commodity Derivative Instruments (10)	Note 13	27	1	26	—	—
Total Contractual Obligations		$16,239	$1,028	$2,989	$1,277	$10,945

(1) References are to the Notes accompanying Item 8. Financial Statements and Supplementary Data.

(2) Long-term debt includes our revolving credit facilities and fixed-rate debt and excludes unamortized discounts, premiums, debt issuance costs and capital lease obligations.

(3) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2018.

(4) Annual capital lease payments exclude regular maintenance and operational costs.

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

(6) Amount includes exit cost obligations resulting from a permanent capacity assignment. In addition, we entered into a permanent capacity assignment in January 2019 which reduced the undiscounted financial commitment by approximately $350 million.

(7) Operating lease obligations represent non-cancelable leases for office buildings, facilities and equipment used in our daily operations, such as drilling rigs, vessels and compressors. Annual lease payments exclude regular maintenance and operational costs.

(8) The table excludes deferred compensation liabilities of $147 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 17. Stock-Based and Other Compensation Plans.

(9) AROs are discounted.

(10) Amount represents commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2018.

Exploration Commitments The terms of some of our PSCs, 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 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.

Continuous Development Obligations Certain of our US onshore assets, such as our Eagle Ford Shale and Delaware Basin properties, are primarily held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas which could be substantial, or exercise options with land owners to extend leases. Failure to meet these obligations may result in the loss of leases.

Leviathan Natural Gas Project The initial development of the Leviathan field requires substantial infrastructure and capital; therefore, we have executed major equipment and installation contracts in support of these activities. As of December 31, 2018, we had entered into approximately $176 million, net, of contracts to support the remaining development activities and bring first production online by the end of 2019.

OIL Contingency As of December 31, 2018, we accrued approximately $28 million for an insurance contingency due to our membership in OIL. OIL is a mutual insurance company which insures specific property, pollution liability and other catastrophic risks. As part of our membership, we are contractually committed to pay termination fees should we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, the potential termination fee is calculated annually based on OIL's past losses, and the liability reflecting this potential charge has been accrued as of December 31, 2018.

Letters of Credit In the ordinary course of business, we maintain letters of credit and bank guarantees with a variety of banks in support of certain performance obligations of our subsidiaries. Outstanding letters of credit and bank guarantees, including Noble Midstream Partners, totaled approximately $89 million at December 31, 2018.

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Ratings Triggers We do not have triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit rating. See Item 1A. Risk Factors - *Indebtedness may limit our liquidity and financial flexibility.*

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the consolidated financial statements requires our management to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the accounting policies, estimates and judgments which management believes are most significant in the application of US GAAP used in the preparation of the consolidated financial statements.

Reserves

Description We estimate proved oil and gas reserves according to the definition of proved reserves provided by the SEC and the Financial Accounting Standards Board (FASB). Reserves estimates have a significant impact on our financial statements as they are used as an input in the calculation of DD&A expense and in impairment assessments for crude oil and natural gas properties and goodwill.

Judgment and Uncertainties The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Commodity prices and development and production costs are factors used in determining reserves economics and reserves estimates. As a result, our reserves estimates will change in the future due to commodity price volatility and cost changes, as well as due to new information obtained from development drilling and production history.

Effect if Actual Results Differ from Assumptions Our reserves estimates are based on year-end cost, development, and production data and on historical 12-month average commodity price data. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil, NGLs and natural gas that are ultimately recovered due to reservoir performance and new geological and geophysical data. Additionally, increases in future drilling, development, production and abandonment costs and changes in commodity prices may result in future revisions to our reserves.

Estimates of proved crude oil, NGL and natural gas reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. For 2018, a 10% reduction in estimates of proved reserves across all properties would have increased DD&A expense by approximately $190 million.

A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of crude oil and natural gas properties or goodwill exceeds fair value and could result in an impairment charge, which would reduce earnings. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Oil and Gas Properties – Successful Efforts Method of Accounting

Description We account for crude oil and natural gas properties under the successful efforts method of accounting which results in the capitalization of costs directly related to specific oil and gas reserves when results are positive and expensing of certain costs, including geological and geophysical costs and delay rentals, during the periods the costs are incurred, and, in the case of dry hole costs, in the period the well is deemed non-commercial.

The alternative method of accounting for crude oil and natural gas properties is the full cost method under which geological and geophysical costs, exploratory dry holes and delay rentals are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. In addition, capitalized costs are accumulated in pools on a country-by-country basis. DD&A is computed on a country-by-country basis, and capitalized costs are limited on the same basis through the application of a ceiling test.

Judgment and Uncertainties The determination of the carrying value of our oil and gas properties includes assessment of impairment and the calculation of amortization expense.

In determining whether unproved crude oil and natural gas properties are impaired, we apply significant judgment in assessing entity-specific assumptions and assumptions related to the future economic environment, as well as potential impacts of the political and regulatory climate on future development activity. We also consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

In addition, impairment assessment involves a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to estimate future cash flows related to both proved and unproved reserves. Such assumptions include commodity prices, capital spending, production and abandonment costs and reservoir data. Significant judgment is involved in estimating these factors, and they include uncertainties. In cases where probable and possible reserves cash flows are utilized to assess properties for impairment, we use the same pricing, cost and future production assumptions. For the purpose of impairment testing as of December 31, 2018, we used the five-year strip prices for crude oil and natural gas, with prices subsequent to the fifth year held constant as the benchmark price, unless contractual arrangements designate the price to be used, in the undiscounted future net cash flows. Capital and operating costs were estimated assuming 0% escalation.

For capitalized exploratory well costs, significant judgment is required in order to determine whether sufficient progress has been made in assessing the reserves and the economic and operational viability of a project in order to continue capitalization of such costs. Such assessment requires consideration of the following factors: commitment of project personnel, costs incurred to assess reserves and potential development, progress of economic, legal, political and environmental aspects of potential development, existence or active negotiations of agreements with governments and venture partners or sales contracts with customers, identification of existing transportation and other infrastructure that is or will be available for the project and other factors. Consideration of these factors requires us to make assumptions and apply judgment to assess industry and economic conditions, as well as our future drilling and development plans. Future changes in our exploratory and drilling activities or economic conditions may result in the determination not to pursue certain projects, resulting in future write-offs of the capitalized exploratory well costs.

Calculation of unit-of-production rates for DD&A purposes is performed on a field-by-field basis and includes estimation of the period-end reserves base and production data for each respective field, including estimates of production for non-operated properties.

Effect if Actual Results Differ from Assumptions At year-end, the net book value of our unproved properties includes significant amounts allocated in previous business combinations or acquisitions. Unfavorable revisions to our reserves and/or changes in our exploration and development plans or the economic, political or regulatory environment in areas where we operate, or changes in the availability of funds for future activities may result in abandonment and impairment of unproved leases and oil and gas properties. Unfavorable changes in pricing and cost assumptions in the future may result in negative revisions to proved and/or unproved reserves and associated cash flows, causing us to record impairment of proved and/or unproved oil and gas properties. An impairment of a proved or unproved property could result in a significant decrease in earnings.

If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs would be charged to exploration expense in future periods, resulting in a decrease in earnings. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Furthermore, a change in groupings of our oil and gas properties for the purpose of the DD&A calculation and impairment review could affect the calculation of unit-of-production rates, DD&A expense and determination of impairment.

Purchase Price Allocations and Resulting Goodwill

Description We use the acquisition method to account for certain business combinations. This method requires us to allocate the acquisition cost to assets acquired and liabilities assumed based on fair values as of the acquisition date, with any difference recorded either as goodwill or gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed. Any goodwill recognized is subsequently assessed for impairment through an initial qualitative assessment, followed by the application of the quantitative test.

Judgment and Uncertainties Estimation of the fair values of assets acquired and liabilities assumed in a business combination requires that we make various assumptions, the most significant of which relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. In most cases, sufficient market data is not available regarding the fair values of proved and unproved properties, and we prepare estimates of such properties based on the fair value of associated crude oil, NGL and natural gas reserves utilizing the income approach. The primary assumptions used to arrive at estimates of future net cash flows used in the income approach include reserves quantities, future commodity prices, and capital and operating costs. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risk factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors that, in management's judgment, are reasonable.

For other assets acquired in business combinations, we use judgment to determine the appropriate combination of available cost and market data and/or estimated cash flows to determine the fair values. Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

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The initial qualitative goodwill impairment assessment also involves significant judgment, as we are required to examine relevant events and circumstances which could have a negative impact on our goodwill, such as: macroeconomic conditions; industry and market conditions, including commodity prices; cost factors; overall financial performance; reporting unit dispositions and acquisitions; and other relevant entity-specific events. Management must make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. We use a combination of the income and market approaches to determine the fair value of a reporting entity. These approaches result in fair values that are subject to a high degree of estimation uncertainty as they require us to make assumptions and apply judgment to various parameters that are sensitive to industry, market and economic conditions. Inputs for the income approach include estimates of both proved reserves and risk-adjusted unproved reserves; market prices considering forward commodity price curves as of the measurement date; and operating, administrative and capital costs adjusted for inflation. Inputs for the market approach include selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums as well as selected company financial metrics, such as EBITDAX.

Effect if Actual Results Differ from Assumptions Although we based the fair value estimate of the US reporting unit on assumptions we believed to be reasonable, those assumptions were inherently unpredictable and uncertain. Changes in assumptions, such as an increase in commodity prices or a decrease in discount rates, could have resulted in a lesser amount of impairment or no goodwill impairment at all. For example, we conducted our annual goodwill impairment assessment, concluding that the goodwill allocated to the Texas reporting unit was fully impaired. See Item 8. Financial Statements and Supplementary Data – Note 6. Goodwill Impairment.

The estimated fair values assigned to assets acquired and liabilities assumed in a purchase price allocation can have a significant effect on future results of operations. For example, a higher fair value assigned to a property results in higher DD&A expense, which results in lower net income. In addition, if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than the estimates originally used to determine fair value, the resulting reductions in future cash flows could indicate that a property is impaired.

In addition, the estimates used in our goodwill impairment test do not constitute forecasts or projections of future results of operations, but are rather estimates and assumptions based on historical results and assessments of macroeconomic factors as of the valuation date. We believe that our estimates and assumptions are reasonable, but they are subject to change from period to period. Actual results of operations and other factors will likely differ from the estimates used in our discounted cash flow valuation and it is possible that differences could be material. In the event of a prolonged industry downturn, commodity prices could again become depressed or decline, thereby causing the fair values of our reporting units to decline, which could result in an impairment of goodwill. A property or goodwill impairment would have no effect on cash flows, but would result in a decrease in net income for the period in which the impairment is recorded.

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

Exit Costs

Description Our consolidated balance sheets include accrued exit cost liabilities relating to retained Marcellus Shale natural gas firm transportation contracts.

Judgment and Uncertainties We are required to make significant judgments and estimates regarding the timing and amount of recognition of exit cost liabilities, taking into consideration current commercialization activities related to the retained firm transportation contracts and/or the potential occurrence of a cease-use date. We must consider, among other factors, the status of negotiations with counterparties regarding permanent assignment or capacity release of our contract commitments and the likelihood of capacity utilization through purchase of third-party natural gas, which would reduce unutilized volume commitments.

Additionally, any subsequent changes in interest rates and/or credit risk will affect the discount rate used to calculate the present value of expected future cash flows associated with our existing contract commitments.

There are inherent uncertainties surrounding the recording of exit cost liabilities, and, in future periods, a number of factors could significantly change our estimate of such obligations or result in recognition of additional liability.

Effect if Actual Results Differ from Assumptions Although we based the initial fair value estimate of our accrued exit cost liabilities on assumptions we believed to be reasonable, those assumptions were inherently unpredictable and uncertain. Changes in assumptions, such as a reduced likelihood of capacity utilization through purchase of third-party natural gas, could have resulted in a higher exit cost accrual, higher current period expense, and lower future expense. For example, as of December 31, 2018, we have a significant remaining financial commitment associated with Marcellus Shale firm transportation contracts. We cannot guarantee that our current commercialization efforts for these contracts will be successful, and, in the future, we may recognize substantial future liabilities, at fair value, for the net amount of the estimated remaining commitments under these contracts, with the offsetting charge reducing our earnings. See Item 8. Financial Statements and Supplementary Data – Note 10. Marcellus Shale Firm Transportation Contracts.

Income Tax Expense and Deferred Tax Assets

Description Our consolidated balance sheets include deferred tax assets and liabilities relating to temporary differences, operating losses, and tax-credit carryforwards. Valuation allowances may reduce the deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Judgment and Uncertainties Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws as well as assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

In determining whether a valuation allowance is required for our deferred tax asset balances, we consider all available evidence (both positive and negative) including, among other factors, current financial position, results of operations, projected future taxable income, tax planning strategies and new tax legislation. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production rates, timing of development activities, profitability of future business strategies and forecasted economics in the oil and gas industry. Judgment is also required in considering the relative weight of negative and positive evidence. Additionally, changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and will affect valuation of deferred tax balances in the future.

Effect if Actual Results Differ from Assumptions We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. Changes to our current financial position, results of operations, projected future taxable income, tax planning strategies and/or new tax legislation may be deemed significant enough to necessitate a change to our deferred tax asset valuation allowances in the future, in which case the increases or decreases could significantly impact net income through offsetting changes in income tax expense. See Item 8. Financial Statements and Supplementary Data – Note 12. Income Taxes.

Item 7A. 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.

Derivative Instruments Held for Non-Trading Purposes Due to commodity price volatility, we may use derivative instruments as a means of managing our exposure to price changes.

At December 31, 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 asset position with a fair value of $153 million. Based on the December 31, 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 decrease the fair value of our net commodity derivative asset by approximately $272 million.

Even with certain hedging arrangements in place to mitigate the effect of commodity price volatility, our 2019 revenues and results of operations could be adversely affected if commodity prices were to decline. See Item 1A. Risk Factors – *Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices* and Item 8. Financial Statements and Supplementary Data – Note 13. 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 December 31, 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% at December 31,

2018. 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.

ed $716 million, approximately 25%

In addition, issuances of commercial paper under our commercial paper program and borrowings under the Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility and Noble Midstream Services Term Loan Credit 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 December 31, 2018, we may invest in such instruments in the future in order to mitigate interest rate risk. A change in the interest rate applicable to our short-term investments or amounts, if any, outstanding under the above-named facilities would have a de minimis impact on our consolidated net income. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, NGL and natural gas production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, for example certain local working capital items, are denominated in a foreign currency and remeasured into US dollars. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative and tax liabilities. Net transaction gains and losses were de minimis for 2018, 2017 and 2016.
We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

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Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate "internal control over financial reporting," as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2018, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control – Integrated Framework (2013)*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2018, based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2018 which is included herein.

Noble Energy, Inc.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
Noble Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 19, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2002.

Houston, Texas
February 19, 2019

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Report of Independent Registered Public Accounting Firm
To the Board of Directors and Shareholders
Noble Energy, Inc.:
Opinion on Internal Control Over Financial Reporting
We have audited Noble Energy, Inc.'s and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 19, 2019 expressed an unqualified opinion on those consolidated financial statements.
Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.
Definition and Limitations of Internal Control Over Financial Reporting
A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas

February 19, 2019

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Noble Energy, Inc.
Consolidated Statements of Operations and Comprehensive Income (Loss)
(millions, except per share amounts)

	Year Ended December 31,		
	2018	2017	2016
Revenues			
Oil, NGL and Gas Sales	$4,461	$4,060	$3,389
Sales of Purchased Oil and Gas and Other	525	196	102
Total	4,986	4,256	3,491
Costs and Expenses			
Production Expense	1,197	1,141	1,100
Exploration Expense	129	188	925
Depreciation, Depletion and Amortization	1,934	2,053	2,454
Loss on Marcellus Shale Upstream Divestiture and Other	—	2,379	—
Gain on Divestitures, Net	(843)	(326)	(238)
Asset Impairments	206	70	92
Goodwill Impairment	1,281	—	—
General and Administrative	385	415	399
Other Operating Expense, Net	346	138	135
Total	4,635	6,058	4,867
Operating Income (Loss)	351	(1,802)	(1,376)
Other Expense			
(Gain) Loss on Commodity Derivative Instruments	(63)	(63)	139
Loss (Gain) on Extinguishment of Facility or Debt	8	98	(80)
Interest, Net of Amount Capitalized	282	354	328
Other Non-Operating (Income) Expense, Net	(16)	—	9
Total	211	389	396
Income (Loss) Before Income Taxes	140	(2,191)	(1,772)
Income Tax Expense (Benefit)	126	(1,141)	(787)
Net Income (Loss) and Comprehensive Income (Loss) Including Noncontrolling Interests	14	(1,050)	(985)
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	80	68	13
Net Loss and Comprehensive Loss Attributable to Noble Energy	$(66)	$(1,118)	$(998)
Loss Attributable to Noble Energy per Common Share			
Basic and Diluted	$(0.14)	$(2.38)	$(2.32)
Weighted Average Number of Shares Outstanding			
Basic and Diluted	483	469	430

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 716	$ 675
Accounts Receivable, Net	616	748
Other Current Assets	418	780
Total Current Assets	1,750	2,203
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	29,002	29,678
Property, Plant and Equipment, Other	891	879
Total Property, Plant and Equipment, Gross	29,893	30,557
Accumulated Depreciation, Depletion and Amortization	(11,474)	(13,055)
Total Property, Plant and Equipment, Net	18,419	17,502
Other Noncurrent Assets	731	461
Goodwill	110	1,310
Total Assets	$ 21,010	$ 21,476
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,207	$ 1,161
Other Current Liabilities	519	578
Total Current Liabilities	1,726	1,739
Long-Term Debt	6,574	6,746
Deferred Income Taxes	1,061	1,127
Other Noncurrent Liabilities	1,165	1,245
Total Liabilities	10,526	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; 520 Million and 529 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,203	8,438
Accumulated Other Comprehensive Loss	(32)	(30)
Treasury Stock, at Cost; 39 Million Shares	(730)	(725)
Retained Earnings	1,980	2,248
Noble Energy Share of Equity	9,426	9,936
Noncontrolling Interests	1,058	683
Total Equity	10,484	10,619
Total Liabilities and Equity	$ 21,010	$ 21,476

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

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

	Year Ended December 31,		
	2018	2017	2016
Cash Flows From Operating Activities			
Net Income (Loss) Including Noncontrolling Interests	$14	$(1,050)	$(985)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,934	2,053	2,454
Loss on Marcellus Shale Upstream Divestiture and Other	—	2,379	—
Gain on Divestitures, Net	(843)	(326)	(238)
Asset Impairments	206	70	92
Goodwill Impairment	1,281	—	—
Deferred Income Tax Benefit	(70)	(1,227)	(984)
Loss (Gain) on Extinguishment of Facility or Debt, Net	4	98	(80)
(Gain) Loss on Commodity Derivative Instruments	(63)	(63)	139
Net Cash (Paid) Received in Settlement of Commodity Derivative Instruments	(161)	13	569
Stock Based Compensation	62	104	77
Undeveloped Leasehold Impairment	1	62	93
Dry Hole Cost	1	9	579
Other Adjustments for Noncash Items Included in Net Income (Loss)	17	(21)	95
Changes in Operating Assets and Liabilities			
Decrease (Increase) in Accounts Receivable	156	(171)	(151)
(Decrease) Increase in Accounts Payable	(63)	248	(111)
Increase (Decrease) in Current Income Taxes Payable	22	(36)	(32)
Other Current Assets and Liabilities, Net	(36)	(71)	(76)
Other Operating Assets and Liabilities, Net	(126)	(120)	(90)
Net Cash Provided by Operating Activities	2,336	1,951	1,351
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(3,279)	(2,649)	(1,541)
Acquisitions, Net of Cash Received	(653)	(954)	30
Proceeds from Divestitures	1,999	2,073	1,241
Marcellus Shale Acreage Exchange Consideration	—	—	(213)
Other	2	(87)	82
Net Cash Used in Investing Activities	(1,931)	(1,617)	(401)
Cash Flows From Financing Activities			
Proceeds from Revolving Credit Facility	1,580	1,585	—
Repayment of Revolving Credit Facility	(1,810)	(1,355)	—
Proceeds from Term Loan Facility	—	—	1,400
Repayment of Term Loan Facility	—	(550)	(850)
Proceeds from Noble Midstream Services Revolving Credit Facility	777	325	—
Repayment of Noble Midstream Services Revolving Credit Facility	(802)	(240)	—
Proceeds from Noble Midstream Services Term Loan Credit Facility	500	—	—
Repayment of Senior Notes	(384)	(1,114)	(1,383)
Repayment of Clayton Williams Energy Long-term Debt	—	(595)	—
Proceeds from Issuance of Senior Notes	—	1,086	—
Dividends Paid, Common Stock	(208)	(190)	(172)

Purchase and Retirement of Common Stock	(295)	—	—
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	312	299
Contributions from Noncontrolling Interest Owners	353	19	—
Other	(110)	(114)	(62)
Net Cash Used in Financing Activities	(399)	(831)	(768)
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	6	(497)	182
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	713	1,210	1,028
Cash, Cash Equivalents, and Restricted Cash at End of Period	$719	$713	$1,210

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

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

	Attributable to Noble Energy						
	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Non-controlling Interests	Total Equity
December 31, 2015	$5	$ 6,360	$ (33)	$ (688)	$ 4,726	$ —	$ 10,370
Net (Loss) Income	—	—	—	—	(998)	13	(985)
Stock-based Compensation	—	68	—	—	—	—	68
Exercise of Stock Options	—	24	—	—	—	—	24
Dividends (40 cents per share)	—	—	—	—	(172)	—	(172)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	299	299
Other	—	(2)	2	(4)	—	—	(4)
December 31, 2016	$5	$ 6,450	$ (31)	$ (692)	$ 3,556	$ 312	$ 9,600
Net (Loss) Income	—	—	—	—	(1,118)	68	(1,050)
Clayton Williams Energy Acquisition	—	1,876	—	(25)	—	—	1,851
Stock-based Compensation	—	100	—	—	—	—	100
Exercise of Stock Options	—	10	—	—	—	—	10
Dividends (40 cents per share)	—	—	—	—	(190)	—	(190)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	312	312
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(28)	(28)
Other	—	2	1	(8)	—	19	14
December 31, 2017	$5	$ 8,438	$ (30)	$ (725)	$ 2,248	$ 683	$ 10,619
Net (Loss) Income	—	—	—	—	(66)	80	14
Stock-based Compensation	—	78	—	—	—	—	78
Dividends (43 cents per share)	—	—	—	—	(208)	—	(208)
Purchase and Retirement of Common Stock	—	(295)	—	—	—	—	(295)
Clayton Williams Energy Acquisition	—	(25)	—	—	—	—	(25)
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(51)	(51)
Contributions from Noncontrolling Interest Owners	—	—	—	—	—	353	353
Other	—	7	(2)	(5)	6	(7)	(1)
December 31, 2018	$5	$ 8,203	$ (32)	$ (730)	$ 1,980	$ 1,058	$ 10,484

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

Note 1. Summary of Significant Accounting Policies

General Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our historical operating areas include: US onshore, primarily the DJ Basin, Delaware Basin, Eagle Ford Shale and Marcellus Shale (until June 2017); US offshore Gulf of Mexico (until April 2018); Eastern Mediterranean; and West Africa. Our Midstream segment develops, owns, operates and acquires domestic midstream infrastructure assets, or invests in other midstream entities, with current focus areas being the DJ and Delaware Basins.

Basis of Presentation and Consolidation We use accounting policies that conform to US GAAP. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated upon consolidation. For the periods presented, net income or loss is materially consistent with comprehensive income or loss.

Segment Information Accounting policies are consistent across geographical segments. Transfers between segments are accounted for at market value. We do not consider interest income or expense and income tax benefit or expense in our evaluation of the performance of geographical segments. See Note 3. Segment Information.

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

Noncontrolling Interests In third quarter 2016, Noble Midstream Partners, a subsidiary of Noble Energy, completed its initial public offering of common units. As a result, we present our consolidated financial statements with a noncontrolling interest section representing the public's ownership in Noble Midstream Partners. We also present third-party ownership in Noble Midstream Partners' consolidated non-wholly owned subsidiaries as noncontrolling interests. See Note 5. Acquisitions and Divestitures.

Equity Method of Accounting We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. Our equity investees own and operate various midstream assets which we consider an essential component of our business and a necessary and integral element to our value chain involving the monetization of natural gas. With our partners, we engage in joint strategic operational and financial decision making for these entities.

In order to reflect the economics associated with our integrated upstream value chain described above, we include income from equity method investees as a component of revenues in our consolidated statements of operations.

We carry equity method investments at our share of net assets of the equity investees plus loans and advances, and include the investments in other noncurrent assets on our consolidated balance sheets. Within our consolidated statements of cash flows, activity is reflected within cash flows provided by operating activities and cash flows used in investing activities. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investees and is not included in our income tax provision in our consolidated statements of operations. See Note 15. Equity Method Investments.

Foreign Currency The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in foreign currencies are remeasured into US dollars and recorded in the financial statements at prevailing foreign exchange rates. Transaction gains or losses are included in other non-operating (income) expense, net in the consolidated statements of operations.

Use of 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.

Estimated quantities of crude oil, NGL and natural gas reserves are the most significant of our estimates. All of the reserves data included in this Annual Report Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, NGLs and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil, NGL and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil, NGLs and natural gas that are ultimately recovered. Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by senior engineering staff and division management with final approval by the Senior Vice President – Corporate Development and certain members of senior management. See Supplemental Oil and Gas Information (Unaudited).

Other items subject to estimates and assumptions include the carrying amounts of inventory, property, plant and equipment, goodwill, exit costs and AROs, valuation allowances for receivables and deferred income tax assets, and valuation of derivative instruments, among others. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. Declines in commodity prices could result in a reduction in our fair value estimates and cause us to perform analyses to determine if our oil and gas properties are impaired. As future commodity prices cannot be determined accurately, actual results could differ significantly from our estimates.

Reclassifications The revenues and expenses associated with mitigating Marcellus Shale retained firm transportation contracts, including costs associated with exiting certain of those contracts, were reclassified from our oil and gas exploration and production segment to Corporate as these items are not representative of retained upstream operations. See Note 3. Segment Information.

Certain other prior-period amounts have been reclassified to conform to the current period presentation.

Fair Value Measurements Fair value measurements are based on a hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy is as follows:

- Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities.
- 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.
- Level 3 measurements are fair value measurements which use unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. We use Level 1 inputs when available, as Level 1 inputs generally provide the most reliable evidence of fair value. See Note 14. Fair Value Measurements and Disclosures.

Cash and Cash Equivalents For purposes of reporting cash flows, cash and cash equivalents include unrestricted cash on hand and investments with original maturities of three months or less at the time of purchase.

Accounts Receivable and Allowance for Doubtful Accounts Our accounts receivable result from sales of crude oil, NGL and natural gas production and joint interest billings to our partners for their share of expenses on joint venture projects for which we are the operator. The majority of these receivables have payment terms of 30 days or less. Our accounts receivable reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. We continually monitor the creditworthiness of the counterparties and we have obtained credit enhancements from some parties in the form of parental guarantees or letters of credit.

We routinely assess the recoverability of all material receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. See Note 2. Additional Financial Statement Information.

Inventories Inventories consist primarily of tubular goods and production equipment used in our oil and gas operations and crude oil produced but not yet sold. Materials and supplies inventories are stated at the lower of cost or net realizable value. The assets will be reduced to their fair value if the carrying amount exceeds net realizable value. The cost of crude oil inventory includes production costs and depreciation, depletion and amortization (DD&A) of oil and gas properties. See Note 2. Additional Financial Statement Information.

Property, Plant and Equipment Significant accounting policies for our property, plant and equipment are as follows:

Oil and Gas Properties (Successful Efforts Method of Accounting) We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved crude oil, NGL and natural gas reserves on a field-by-field basis, as estimated by our qualified petroleum engineers. Costs of certain gathering facilities or processing plants serving a number of properties or used for third-party processing are depreciated using the straight-line method over the useful lives of the assets ranging from three to thirty years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Costs related to repair and maintenance activities are expensed as incurred.

Proved Property Impairment For our proved properties, we routinely assess whether impairment indicators arise during any given quarter and have processes in place to ensure that we become aware of such indicators. Impairment indicators include, but are not limited to, sustained decreases in commodity prices, negative revisions of proved reserves, and increases in development or operating costs. In the event that impairment indicators exist, we conduct an impairment test. Under such test, we estimate future net cash flows expected in connection with the property and compare such future net cash flows to the carrying amount of the property to determine if the carrying amount is recoverable. Other long-lived assets, such as our midstream assets, are evaluated in a manner consistent with our policy for proved property.

When the carrying amount of a property exceeds its estimated undiscounted future net cash flows, the carrying amount is reduced to estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future crude oil and natural gas production, commodity prices based on published forward commodity price curves or contract prices as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

We recorded impairment charges in 2018, 2017 and 2016 and it is possible that other assets could become impaired in the future. See Note 14. Fair Value Measurements and Disclosures.

Unproved Property Impairment Our unproved properties consist of leasehold costs and allocated value to probable and possible reserves resulting from acquisitions. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss at the time of impairment by providing an impairment allowance. In determining whether a significant unproved property is impaired, we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

When we have allocated fair value to an unproved property as the result of a transaction accounted for as a business combination, we use a future cash flow analysis to assess the unproved property for impairment. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil, NGL and natural gas reserves, future commodity prices and future costs to produce the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors.

It is possible that unproved oil and gas properties, including undeveloped leases, could become impaired in the future if commodity prices decline or if there are changes in exploration plans or the timing and extent of development activities. See Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Properties Acquired in Business Combinations When sufficient market data is not available, we determine the fair values of proved and unproved oil and gas properties acquired in transactions accounted for as business combinations by preparing estimates of cash flows from the production of crude oil, NGL and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. When estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

For other assets acquired in business combinations, we use a combination of available cost and market data and/or estimated cash flows to determine the fair values.

Assets Held for Sale We occasionally market oil and gas properties for sale. At the end of each reporting period, we evaluate properties being marketed to determine whether any should be reclassified as held for sale. The held-for-sale criteria include: a commitment to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held for sale on our consolidated balance sheets and will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell.

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive international projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities, permits and approvals and we believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Property, Plant and Equipment, Other Other property includes automobiles, trucks, airplanes, office furniture, computer equipment, buildings, leasehold improvements and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets, ranging from three to thirty years. Other property also includes linefill, which is recorded at cost to produce into the production line. Linefill is not subject to depreciation but is reviewed for impairment.

Capitalization of Interest We capitalize interest costs associated with the development and construction of significant properties or projects to bring them to a condition and location necessary for their intended use, which for crude oil and natural gas assets is at first production from the field. Interest is capitalized using an interest rate equivalent to the weighted average interest rate we pay on long-term debt, including our unsecured revolving credit facilities and bonds. Capitalized interest is included in the cost of oil and gas assets and is amortized with other costs on a unit-of-production basis. Capitalized interest totaled $73 million in 2018, $49 million in 2017, and $84 million in 2016.

Asset Retirement Obligations Asset Retirement Obligations (AROs) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of a liability for an ARO in the period in which we have an existing legal obligation associated with the retirement that can reasonably be estimated. The associated asset retirement cost is capitalized as part of the carrying value of the oil and gas asset. The asset retirement cost is recorded at estimated fair value, measured by the expected future cash outflows required to satisfy the obligation discounted at our credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense included in DD&A expense in the consolidated statements of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset. See Note 8. Asset Retirement Obligations.

Goodwill Goodwill is not amortized to earnings but is assessed for impairment at the reporting unit level on an annual basis, or more frequently as circumstances require. We use qualitative and quantitative assessments to determine whether goodwill is impaired. If we conclude that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, an impairment charge is recognized for the amount by which the carrying amount exceeds the fair value.

We conducted our annual goodwill impairment assessment as of September 30, 2018. As of that date, our consolidated balance sheet included goodwill of $1.4 billion, of which $1.3 billion was allocated to our Texas reporting unit, included within our oil and gas exploration and production segment, and $110 million was allocated to our Midstream reporting unit. At that time, we concluded that goodwill was not impaired. During fourth quarter 2018, we considered changes to facts and circumstances, particularly the decline in WTI strip pricing, increase in operating and capital costs, as well as our development plan, and concluded that the goodwill allocated to the Texas reporting unit was fully impaired and recorded a charge of $1.3 billion. See Note 6. Goodwill Impairment.

Intangible Assets Intangible assets consist of customer contracts and relationships acquired by Noble Midstream Partners through Black Diamond in its acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte). We recorded the intangible assets at their estimated fair values at the date of acquisition. Amortization is calculated using the straight-line method, which reflects the pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible assets, which is currently over periods of seven to 13 years. As of December 31, 2018, the net book value of our intangible assets was $310 million.

Amortization expense, which is equivalent to accumulated amortization for 2018, of $30 million is included in DD&A expense in our consolidated statements of operations and statements of cash flows. 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 5. Acquisitions and Divestitures.

Exit Costs In accordance with Accounting Standards Codification (ASC) 420 – *Exit or Disposal Cost Obligations*, we recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. The recognition and fair value estimation of an exit cost liability requires that management take into account certain estimates and assumptions including: the determination of whether a cease-use date has occurred (defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services); the amount, if any, of economic benefit that is expected to be obtained from a contract through partial use or release; and our estimate of costs that will continue to be incurred under the contract. We record exit cost liabilities at estimated fair value, based on expected future cash outflows required to satisfy the obligation, net of estimated recoveries, and discounted. In periods subsequent to initial measurement, changes to an exit cost liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, will be recognized as an adjustment to the liability in the period of the change.

Exit cost liabilities are included in other current and other noncurrent liabilities on our consolidated balance sheets. Exit costs, and associated accretion expense, are included in other operating expense, net in our consolidated statements of operations.

Accrued exit costs at December 31, 2018 and 2017 relate primarily to estimated costs associated with Marcellus Shale contracts. See Note 10. Marcellus Shale Firm Transportation Commitments.

Derivative Instruments and Hedging Activities All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded on our consolidated balance sheets as either an asset or liability and are measured at fair value. We account for our commodity derivative instruments using mark-to-market accounting and recognize all gains and losses in earnings during the period in which they occur. Our consolidated statements of cash flows include the non-cash portion of gain and loss on commodity derivative instruments, which represents the difference between the total gain and loss on commodity derivative instruments and the cash received or paid on settlements of commodity derivative instruments during the period.

We offset the fair value amounts recognized for derivative instruments against the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral (commonly referred to as a “margin”) must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master agreement with netting clauses. See Note 13. Derivative Instruments and Hedging Activities.

Stock-Based Compensation Restricted stock and stock options issued to employees and directors are recorded on grant-date at fair value. Expense is recognized on a straight-line basis over the employee’s and director’s requisite service period (generally the vesting period of the award) in the consolidated statements of operations. In 2016, we issued cash-settled awards to certain employees in lieu of a portion of restricted stock and stock options. We recognize the value of cash-settled awards utilizing the liability method as defined under ASC Topic 718, *Compensation – Stock Compensation*. The fair value of liability awards is remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. See Note 17. Stock-Based and Other Compensation Plans.

Other Postretirement Benefit Plans We recognize the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to accumulated other comprehensive loss (AOCL), net of tax. The amount remaining in AOCL at December 31, 2018 represents unrecognized net actuarial loss and unrecognized prior service cost related to our restoration plan. These amounts are currently being recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Any actuarial gains and losses that arise during the plan year, but which are not required to be recognized as net periodic benefit cost in the same period, are recognized as a component of AOCL.

Contingencies We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See Note 11. Commitments and Contingencies.

We self-insure the medical and dental coverage provided to certain employees, and the deductibles for workers’ compensation, automobile liability and general liability coverage. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss.

Income Taxes and Impact of Tax Reform Legislation We are subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions.

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax return or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements.

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted.

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 affecting us. See Note 12. Income Taxes.

Treasury Stock We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in shareholders' equity in the consolidated balance sheets.

Revenue Recognition We recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer, using a five-step process, in accordance with ASC 606 – *Revenue from Contracts with Customers*. See Note 4. Revenue from Contracts with Customers.

Basic and Diluted Earnings (Loss) Per Share Attributable to Noble Energy Basic earnings (loss) per share (EPS) of our common stock is computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of our common stock includes the effect of outstanding common stock equivalents such as stock options, shares of restricted stock, and/or shares of our stock held in a rabbi trust, except in periods in which there is a net loss. In the event of a net loss, we exclude the effect of outstanding common stock equivalents from the calculation of diluted EPS as the inclusion would be anti-dilutive.

Recently Issued Accounting Standards

Leases In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-02 (ASU 2016-02): *Leases.* The standard requires lessees to recognize a right of use asset (ROU asset) and lease liability on the balance sheet for the rights and obligations created by leases. ASU 2016-02 also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. In July 2018, the FASB issued Accounting Standards Update No. 2018-11 (ASU 2018-11): *Leases (Topic 842): Targeted Improvements*, which provides for an alternative transition method by allowing entities to initially apply the new leases standard at the adoption date (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption (comparative periods presented in the financial statements will continue to be in accordance with current GAAP (Topic 840, Leases)). The standard is effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted.

In the normal course of business, we enter into capital and operating lease agreements to support our exploration and development operations and lease assets, such as drilling rigs, platforms, field services and well equipment, office space and other assets. We adopted the new standard on the effective date of January 1, 2019, using a modified retrospective approach as permitted under ASU 2018-11.

The new standard provides a number of optional practical expedients in transition. We expect to:

- elect the package of 'practical expedients', which permits us not to reassess under the new standard our prior conclusions about lease identification, lease classification and initial direct costs;
- elect the practical expedient pertaining to land easements and plan to account for existing land easements under our current accounting policy;
- elect the short-term lease recognition exemption for all leases that qualify and, as such, no ROU asset or lease liability will be recorded on the balance sheet and no transition adjustment will be required for short-term leases; and
- elect the practical expedient to not separate lease and non-lease components for all of our leases.

We do not expect to elect the hindsight practical expedient in determining the lease term and assessing impairment of ROU assets when transitioning to ASC 842.

We continue to execute a project plan, which includes contract review and assessment, data collection, and evaluation of our systems, processes and internal controls. In addition, we have implemented a new lease accounting software which will facilitate the adoption of this standard.

While we are finalizing our assessment of the effect of adoption, we do not expect the adoption and implementation of this standard will have a material effect on our financial statements. We estimate the most significant impact will relate to the recognition of new ROU assets and lease liabilities on our balance sheet for operating leases, as well as additional disclosures. Consequently, with adoption, we expect to recognize additional operating liabilities ranging between $200 million to $350 million with corresponding ROU assets of the same amount based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases.

Financial Instruments: Credit Losses In June 2016, the FASB issued Accounting Standards Update No. 2016-13 (ASU 2016-13): *Financial Instruments – Credit Losses*, which replaces the incurred loss impairment methodology with a methodology that reflects expected credit losses. The update is intended to provide financial statement users with more useful information about expected credit losses. The amended standard is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. From evaluation of our current credit portfolio, which includes receivables for commodity sales, joint interest billings due from partners and other receivables, historical credit losses have been de minimis and we believe that our expected future credit losses would not be significant. As such, we do not believe adoption of the standard will have a material impact on our financial statements.

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

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

Recently Adopted Accounting Standards

Topic 606, Revenue from Contracts with Customers In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates *Topic 606, Revenue from Contracts with Customers* (ASC 606). We adopted ASC 606 on January 1, 2018, using the modified retrospective method. See Note 4. Revenue from Contracts with Customers.

Statement of Cash Flows – Restricted Cash In November 2016, the FASB issued Accounting Standards Update No. 2016-18 (ASU 2016-18): *Statement of Cash Flows – Restricted Cash*. We adopted ASU 2016-18 in the first quarter of 2018, using the retrospective method. ASU 2016-18 requires that restricted cash and cash equivalents be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. There are no other impacts on our results of operations, financial condition or cash flows.

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 early adopted this ASU in fourth quarter 2018. This adoption did not have a material impact on our financial statements.

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 Reform Legislation. ASU 2018-02 is effective for annual and interim periods beginning after December 15, 2018, with early adoption permitted. We early adopted this ASU in fourth quarter 2018, reclassifying the tax effect of approximately $6 million stranded in accumulated other comprehensive income to retained earnings. This adoption did not have a material impact on our financial statements.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 2. Additional Financial Statement Information

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

	Year Ended December 31,		
(millions)	2018	2017	2016
Sales of Purchased Oil and Gas and Other			
Sales of Purchased Oil and Gas [1]	$275	$—	$—
Income from Equity Method Investees	172	177	102
Midstream Services Revenues - Third Party	78	19	—
Total	$525	$196	$102
Production Expense			
Lease Operating Expense	$576	$571	$542
Production and Ad Valorem Taxes	190	118	57
Gathering, Transportation and Processing Expense	393	432	480
Other Royalty Expense	38	20	21
Total	$1,197	$1,141	$1,100
Exploration Expense			
Leasehold Impairment and Amortization	$1	$62	$148
Dry Hole Cost	1	9	579
Seismic, Geological and Geophysical	22	27	76
Staff Expense	54	55	77
Other	51	35	45
Total	$129	$188	$925
Loss on Marcellus Shale Upstream Divestiture and Other			
Loss on Sale	$—	$2,270	$—
Exit Cost	—	93	—
Other	—	16	—
Total	$—	$2,379	$—
Other Operating Expense, Net			
Marketing Expense [2]	$40	$47	$58
Cost of Purchased Oil and Gas [1]	296	—	—
Clayton Williams Energy Acquisition Expenses	—	100	—
Gain on Asset Retirement Obligation Revisions [3]	(25)	(42)	—
Other, Net	35	33	77
Total	$346	$138	$135

(1) As part of the Saddle Butte Acquisition in first quarter 2018, we acquired certain contracts which include the purchase and sale of crude oil with third parties. In addition, we entered into certain transactions beginning in first quarter 2018 for the purchase of third-party natural gas and the subsequent sale of natural gas to other third parties. The natural gas is transported through firm transportation capacity we retained following the Marcellus Shale upstream divestiture in second quarter 2017 and is part of our mitigation efforts to utilize capacity and reduce our financial commitment. See Note 3. Segment Information and Note 10. Marcellus Shale Firm Transportation Commitments.

(2) Amounts relate to shortfalls in transporting or processing minimum volumes under certain financial commitments primarily in the DJ Basin for 2018 and in the DJ Basin and Marcellus Shale for 2017 (prior to the Marcellus Shale upstream divestiture) and 2016.

(3) Gains due to downward ARO revisions in locations where we have no remaining assets. See Note 8. Asset Retirement Obligations.

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Balance Sheet Information Other balance sheet information is as follows:

	December 31,	
(millions)	2018	2017
Accounts Receivable, Net		
Commodity Sales	$383	$455
Joint Interest Billings [1]	137	207
Other	111	103
Allowance for Doubtful Accounts	(15)	(17)
Total	$616	$748
Other Current Assets		
Commodity Derivative Assets	$180	$—
Inventories, Materials and Supplies	55	66
Inventories, Crude Oil	12	16
Assets Held for Sale [2]	133	629
Restricted Cash [3]	3	38
Prepaid Expenses and Other Assets, Current	35	31
Total	$418	$780
Other Noncurrent Assets		
Equity Method Investments	$286	$305
Customer-Related Intangible Assets, Net [4]	310	—
Mutual Fund Investments	38	57
Net Deferred Income Tax Asset	21	25
Other Assets, Noncurrent	76	74
Total	$731	$461
Other Current Liabilities		
Production and Ad Valorem Taxes	$103	$84
Commodity Derivative Liabilities	1	58
Income Taxes Payable	22	18
Asset Retirement Obligations	118	51
Interest Payable	66	67
Current Portion of Capital Lease Obligations	41	61
Liabilities Associated with Assets Held for Sale [2]	1	55
Compensation and Benefits Payable	83	98
Other Liabilities, Current	84	86
Total	$519	$578
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$147	$197
Asset Retirement Obligations	762	824
Marcellus Shale Exit Cost Accrual	67	76
Production and Ad Valorem Taxes	83	69
Commodity Derivative Liabilities	26	15
Other Liabilities, Noncurrent	80	64
Total	$1,165	$1,245

[1] We bill partners for their share of expenses of joint venture projects for which we are the operator. These projects, especially those in deepwater or remote international locations, can be very capital cost intensive. Our receivables from joint interest billings decreased

significantly in 2018 due to the second quarter 2018 sale of our Gulf of Mexico offshore assets.

(2) Assets held for sale at December 31, 2018 include certain proved and unproved non-core acreage in Reeves County, Texas. 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, our investment in Southwest Royalties, Inc. acquired in the Clayton Williams Energy Acquisition, and the CONE investments, including

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CONE Midstream and CONE Gathering. Liabilities associated with assets held for sale primarily represent ARO and other liabilities to be assumed by the purchaser. See Note 5. Acquisitions and Divestitures.

(3) Balance at December 31, 2018 represents amounts held for the divestiture of certain non-core acreage in the Delaware Basin and Noble Midstream Partners collateral on letters of credit. Balance at December 31, 2017 represents amount held in escrow pending closing of the Saddle Butte Acquisition. See Note 5. Acquisitions and Divestitures.

(4) Amount relates to intangible assets acquired in the Saddle Butte Acquisition. See Note 5. Acquisitions and Divestitures.

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

	December 31,	
(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	$716	$675
Restricted Cash at End of Period	3	38
Cash, Cash Equivalents, and Restricted Cash at End of Period	$719	$713

A significant portion of our cash is located in foreign subsidiaries. The cash is denominated in US dollars and invested in highly liquid money market funds and short term deposits with original maturities of three months or less at the time of purchase. Although our cash and cash equivalents are deposited with major international banks and financial institutions, concentrations of cash in certain foreign locations may increase credit risk. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Supplemental statements of cash flow information are as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$270	$346	$327
Income Taxes Paid, Net	172	121	236
Non-Cash Financing and Investing Activities			
Increase in Capital Lease Obligations	14	—	5

Note 3. Segment Information

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

The geographical reportable segments are in the business of crude oil and natural gas acquisition and exploration, development, and production (Oil and Gas Exploration and Production). The Midstream reportable segment develops, owns, and operates domestic midstream infrastructure assets, as well as invests in other financially attractive midstream projects, with current focus areas being the DJ and Delaware Basins. To assess the performance of Noble

Energy's operating segments, the chief operating decision maker analyzes income (loss) before income taxes. Management believes income (loss) before income taxes provides information useful in assessing the Company's operating and financial performance across periods.
Expenses related to debt, headquarters depreciation, corporate general and administrative expenses, exit costs and certain costs associated with mitigating the effects of our retained Marcellus Shale firm transportation agreements, are recorded at the corporate level.

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		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
Year Ended December 31, 2018								
Crude Oil Sales	$ 2,945	$ 2,548	$ 7	$ 390	$ —	$ —	$ —	$ —
NGL Sales	587	587	—	—	—	—	—	—
Natural Gas Sales	929	435	473	21	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	4,461	3,570	480	411	—	—	—	—
Sales of Purchased Oil and Gas	275	20	—	—	—	142	—	113
Income from Equity Method Investees	172	—	—	132	—	40	—	—
Midstream Services Revenues - Third Party	78	—	—	—	—	78	—	—
Intersegment Revenues	—					351	(351)	
Total Revenues	4,986	3,590	480	543	—	611	(351)	113
Lease Operating Expense	576	480	26	97	—	—	(27)	—
Production and Ad Valorem Taxes	190	184	—	—	—	6	—	—
Gathering, Transportation and Processing Expense	393	533	—	—	—	95	(235)	—
Other Royalty Expense	38	38	—	—	—	—	—	—
Total Production Expense	1,197	1,235	26	97	—	101	(262)	—
Exploration Expense	129	48	7	6	68	—	—	—
DD&A	1,934	1,642	60	115	2	87	(20)	48
(Gain) Loss on Divestitures, Net	(843)	36	(376)	—	—	(503)	—	—
Asset Impairments	206	169	—	—	—	37	—	—
Goodwill Impairment	1,281	1,281	—	—	—	—	—	—
Cost of Purchased Oil and Gas	296	20	—	—	—	136	—	140
Gain on Asset Retirement Obligation Revisions	(25)	—	(8)	—	(17)	—	—	—
(Gain) Loss on Commodity Derivative Instruments	(63)	(70)	—	7	—	—	—	—
Income (Loss) Before Income Taxes	140	(875)	742	305	(53)	726	(60)	(645)
Additions to Long Lived Assets	3,253	2,115	671	12	—	521	(91)	25
Property, Plant and Equipment, Net	18,419	13,044	2,630	805	37	1,742	(145)	306
Year Ended December 31, 2017								
Crude Oil Sales	$ 2,346	$ 1,993	$ 6	$ 347	$ —	$ —	$ —	$ —
NGL Sales	493	493	—	—	—	—	—	—
Natural Gas Sales	1,221	670	528	23	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	4,060	3,156	534	370	—	—	—	—
Income from Equity Method Investees	177	—	—	120	—	57	—	—
Midstream Services Revenues - Third Party	19	—	—	—	—	19	—	—
Intersegment Revenues	—	—	—	—	—	277	(277)	—
Total Revenues	4,256	3,156	534	490	—	353	(277)	—

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		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
Lease Operating Expense	571	466	29	90	—	—	(14)	—
Production and Ad Valorem Taxes	118	115	—	—	—	3	—	—
Gathering, Transportation and Processing Expense	432	550	—	—	—	70	(188)	—
Other Royalty Expense	20	20	—	—	—	—	—	—
Total Production Expense	1,141	1,151	29	90	—	73	(202)	—
Exploration Expense	188	102	2	5	79	—	—	—
DD&A	2,053	1,739	76	146	4	30	(5)	63
Loss on Marcellus Shale Upstream Divestiture and Other	2,379	2,286	—	—	—	—	—	93
Gain on Divestitures, Net	(326)	(325)	(1)	—	—	—	—	—
Asset Impairments	70	63	—	—	7	—	—	—
Clayton Williams Energy Acquisition Expenses	100	100	—	—	—	—	—	—
Gain on Asset Retirement Obligation Revision	(42)	—	—	—	(42)	—	—	—
(Gain) Loss on Commodity Derivative Instruments	(63)	(92)	—	29	—	—	—	—
Loss on Debt Extinguishment	98	—	—	—	—	—	—	98
(Loss) Income Before Income Taxes	(2,191)	(2,365)	413	203	(54)	233	(62)	(559)
Additions to Long Lived Assets	2,851	1,994	411	34	(34)	423	(79)	102
Property, Plant and Equipment, Net	17,502	13,348	2,005	863	25	1,027	(74)	308
Year Ended December 31, 2016								
Crude Oil Sales	$ 1,854	$ 1,439	$ 5	$ 410	$ —	$ —	$ —	$ —
NGL Sales	296	296	—	—	—	—	—	—
Natural Gas Sales	1,239	681	535	23	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	3,389	2,416	540	433	—	—	—	—
Income from Equity Method Investees	102	—	—	50	—	52	—	—
Intersegment Revenues	—	—	—	—	—	200	(200)	—
Total Revenues	3,491	2,416	540	483	—	252	(200)	—
Lease Operating Expense	542	418	37	105	—	—	(18)	—
Production and Ad Valorem Taxes	57	55	—	—	—	2	—	—
Gathering, Transportation and Processing Expense	480	564	—	—	—	44	(128)	—
Other Royalty Expense	21	21	—	—	—	—	—	—
Total Production Expense	1,100	1,058	37	105	—	46	(146)	—
Exploration Expense	925	245	34	483	163	—	—	—
DD&A	2,454	2,103	81	205	6	19	—	40
(Gain) Loss on Divestitures, Net	(238)	23	(261)	—	—	—	—	—
Asset Impairments	92	—	88	—	4	—	—	—

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(millions)	Consolidated	Oil and Gas Exploration and Production				Midstream	Intersegment Eliminations and Other [1]	Corporate
		United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States		
Loss on Commodity Derivative Instruments	139	126	—	13	—	—	—	—
(Loss) Income Before Income Taxes	(1,772)	(1,277)	543	(338)	(199)	176	(51)	(626)
Additions to Long Lived Assets	1,526	1,358	83	54	(6)	58	(53)	32
Property, Plant and Equipment, Net	18,548	14,755	1,872	980	15	594	—	332

(1) 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.

The largest single non-affiliated purchasers of our production were as follows:

	Percentage of Crude Oil Sales	Percentage of Total Oil, NGL & Gas Sales
Year Ended December 31, 2018		
BP [1]	31 %	17 %
Shell [2]	22 %	14 %
Year Ended December 31, 2017		
BP [1]	15 %	10 %
Shell [2]	22 %	13 %
Year Ended December 31, 2016		
Glencore Energy UK Ltd	22 %	12 %
Shell [2]	24 %	13 %

(1) Includes sales to BP North American Funding Company, BP Company Commercial and/or BP Company.

(2) Includes sales to Shell Trading (US) Company and/or Shell International Trading and Shipping Limited.

Both BP and Shell purchased crude oil and condensate domestically from our US onshore operations and from our Gulf of Mexico operations prior to selling the Gulf of Mexico assets in second quarter 2018. No other single purchaser accounted for 10% or more of crude oil, NGL and natural gas sales in 2018. We maintain

Note. 4. 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 (acting as principal). 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 (acting as agent). 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 impact on revenues and expenses for 2018 was less than $1 million and did not affect operating or net income or operating cash flows. The comparative information for the prior period has not been recast and continues to be reported under the accounting standards in effect for the period. Adoption of the new standard did not impact our financial position, and we do not expect that it will do so going forward. See Note 3. Segment Information for disaggregation of revenue by commodity and geographic location.

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

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

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

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

Exploration and Production 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 to downstream customers. 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 to downstream customers is recognized upon delivery, as specified in the contract, when control of the product has transferred to the customer.

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

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

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

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

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

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

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

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

Transaction Price Allocated to Remaining Performance Obligations – Israel Remaining performance obligations represent the transaction price of firm sales arrangements for which volumes have not been delivered. Pursuant to ASC 606, short and long-term interruptible contracts and long-term dedicated production agreements are excluded from the disclosure due to uncertainty associated with estimating future production volumes and future market prices. However, certain of our Tamar 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)	2019	2020	Total
Natural Gas Revenues [1]	$137	$169	$306

[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

Service 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 In first quarter 2018, Noble Midstream Partners acquired an interest in Black Diamond which completed the Saddle Butte Acquisition of a large-scale integrated 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 recorded at the prevailing market prices.

Note 5. Acquisitions and Divestitures

We maintain an ongoing portfolio management program and have engaged in various transactions over recent years.

Year Ended December 31, 2018

Divestiture of Gulf of Mexico Assets On February 15, 2018, we announced that we had signed a definitive agreement to sell our Gulf of Mexico assets, including all of our interests in producing properties and undeveloped acreage, for cash consideration of $480 million, along with the assumption, by the purchaser, of all abandonment obligations associated with the properties. As a result, we recorded impairment expense of $168 million during first quarter 2018. In second quarter 2018, we closed the transaction with an effective date of January 1, 2018. After consideration of customary closing adjustments, to date we have received net proceeds of $384 million and recorded a loss of $24 million.

In addition, a cumulative contingent payment of up to $100 million is payable to us in the period after the closing of the transaction, beginning third quarter 2018, through the end of 2022, determined quarterly, at a rate of $2 per barrel produced by these assets when the average purchase price for Light Louisiana Sweet (LLS) crude oil exceeds $63 per barrel, and if produced crude oil volumes exceed certain minimum thresholds. As of December 31, 2018, $3 million has been accrued related to the contingent payment.

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

The Tamar Petroleum shares were subject to certain temporary lock-up provisions and had no voting rights. 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 were accounted for at fair value and we recorded decreases in fair value of $27 million and dividend income of $31 million during 2018. These amounts are included in other non-operating (income) expense, net, in our consolidated statements of operations.

In fourth quarter 2018, we sold 38.5 million shares of Tamar Petroleum in over the counter transactions for pre-tax proceeds of $163 million, net of transaction expenses. Upon sale, voting rights were restored and granted to the third parties. The sales of the 7.5% working interest in the Tamar field and of the Tamar Petroleum shares are in accordance with the terms of the Israel Natural Gas Framework (Framework) that requires us to reduce our ownership interest in the Tamar field from 32.5% to 25% by year-end 2021.

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

Divestiture of Marcellus Shale CONE Gathering In January 2018, we closed the sale of our 50% interest in CONE Gathering LLC (CONE Gathering) to CNX Resources Corporation. CONE Gathering owns the general partner of CNX Midstream Partners LP (CNX Midstream Partners, NYSE: CNXM). We received proceeds of $309 million in cash and recognized a pre-tax gain of $196 million.

After the sale, we held 21.7 million common units, representing a 34.1% limited partner interest, in CNX Midstream Partners. During 2018, we sold our 21.7 million common units, receiving net proceeds of approximately $387 million, and recognized a gain of $307 million. The investment was previously accounted for under the equity method of accounting.

Divestiture of Greeley Crescent Assets In September 2018, we closed the sale of assets in the Greeley Crescent area of the DJ Basin and received proceeds of $68 million, resulting in no gain or loss recognition on the sale of these assets.

Divestiture of Non-Core Delaware Basin Acreage In December 2018, we closed the sale of certain non-core acreage in the Delaware Basin, receiving proceeds of $63 million, resulting in a pre-tax loss of $16 million.

DJ Acreage Exchange We closed a cashless acreage exchange in the DJ Basin receiving approximately 12,900 net undeveloped acres within core areas of our Mustang and Wells Ranch positions in exchange for approximately 12,300 net undeveloped acres in non-core areas of Mustang and Wells Ranch. No gain or loss was recognized.

Noble Midstream Partners Saddle Butte Acquisition On January 31, 2018, Noble Midstream Partners acquired a 54.4% in 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), which completed the acquisition of Saddle Butte from Saddle Butte Pipeline II, LLC (Saddle Butte Acquisition). Saddle Butte owned a large-scale integrated gathering system, located in the DJ Basin, which we subsequently renamed the Black Diamond gathering system.

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

This transaction was accounted for as a business combination using the acquisition method. The total purchase price was allocated to assets acquired and liabilities assumed based on the fair value at the acquisition date. We have recognized goodwill for the amount of the purchase price exceeding the fair value of the assets acquired. Allocated fair value included: $206 million to property, plant and equipment; $340 million to customer-related intangible assets (acquired customer contracts); and $110 million to implied goodwill. Noble Midstream Partners has completed the purchase price allocation related to this acquisition.

Other Acquisitions and Divestitures During 2018, we closed on the acquisition of other smaller US onshore properties for total cash consideration of $3 million. We also closed the sale of certain other smaller US onshore proved and unproved properties and received total cash consideration of $81 million, recording a gain of $4 million.

Subsequent Events In first quarter 2019, we closed the sale of certain proved and unproved non-core acreage totaling approximately 13,000 net acres in Reeves County, Texas. We received cash consideration of $132 million, recognizing no gain or loss on the sale. As of December 31, 2018, the assets and related liabilities associated with this acreage were considered held for sale and were recorded within other current assets and other current liabilities on our consolidated balance sheets.

In first quarter 2019, Noble Midstream Partners exercised and closed an option with EPIC Midstream Holdings, LP (EPIC) to acquire a 15% equity interest in the EPIC Y-Grade Pipeline. It also exercised an option to acquire a 30% equity interest in the EPIC Crude Oil Pipeline, for which closing is anticipated to occur later in first quarter 2019, subject to certain conditions precedent.

Year Ended December 31, 2017

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

The closing price of our stock on the New York Stock Exchange (NYSE) was $34.17 on April 24, 2017. In connection with the transaction, we borrowed $1.3 billion under our Revolving Credit Facility (defined below) to fund the cash portion of the acquisition consideration, redeem outstanding Clayton Williams Energy debt, pay associated make-whole premiums and pay related fees and expenses. See Note 9. Long-Term Debt.

The acquired assets included 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings in Texas, and an additional 100,000 net acres in other areas of the United States. In addition, upon closing of the acquisition, approximately 64,000 net acres in Reeves County, Texas were dedicated to

Noble Midstream Partners for infield crude oil, natural gas and produced water gathering.

In connection with the acquisition, we incurred acquisition-related costs of $100 million, including $64 million of severance, consulting, investment, advisory, legal and other merger-related fees and $36 million of noncash share-based compensation expense, all of which were expensed and are included in other operating expense, net in our consolidated statements of operations. In addition, we received approximately 720,000 shares of common stock from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of their restricted stock and options pursuant to the purchase and sale agreement, resulting in a $25 million increase in our treasury stock balance.

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Purchase Price Allocation The transaction was accounted for as a business combination using the acquisition method. The following table represents the allocation of the total purchase price of Clayton Williams Energy to the assets acquired and the liabilities assumed based on the fair value at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill.
The following table sets forth our purchase price allocation:

(millions, except per share amounts)	
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 values of Clayton Williams Energy's identifiable assets are as follows:

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

(1) The goodwill, which was associated with the Texas reporting unit included within our oil and gas exploration and production segment, was fully impaired as of December 31, 2018. See Note 6. Goodwill Impairment.

In connection with the acquisition, we assumed, and then subsequently retired, all of Clayton Williams Energy's long-term debt at a cost to us 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 AROs are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and AROs were measured using valuation techniques that convert expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved, possible and probable reserves; (ii) production rates and related development timing; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by management at the time of the valuation and are the most sensitive and may be subject to change.
Results of Operations The results of operations attributable to Clayton Williams Energy are included in our consolidated statements of operations beginning on April 24, 2017. We generated revenues of $99 million and a pre-tax loss of $19 million from the Clayton Williams Energy assets during the period April 24, 2017 to December 31, 2017.

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

Additionally, pro forma earnings for the year ended December 31, 2017 were adjusted to exclude acquisition-related costs of $100 million incurred by Noble Energy and $23 million incurred by Clayton Williams Energy. The pro forma results of operations do not include any cost savings or other synergies that we expect to realize from the Clayton Williams Energy Acquisition or any estimated costs that have been or will be incurred by us to integrate the Clayton Williams Energy assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Clayton Williams Energy Acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	Year Ended December 31,		
(millions, except per share amounts)	2018 [1]	2017	2016
Revenues	$ 4,986	$ 4,304	$ 3,651
Net Income (Loss) and Comprehensive Income (Loss) Attributable to Noble Energy	(66)	(678)	(1,082)
Net Income (Loss) Attributable to Noble Energy per Common Share			
Basic	$ (0.14)	$ (1.39)	$ (2.23)
Diluted	$ (0.14)	$ (1.39)	$ (2.23)

[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 sales price totaled $1.2 billion, and we received $1.0 billion of net cash proceeds, after consideration of customary closing adjustments. The sales price includes additional contingent consideration of up to $100 million structured as three separate payments of $33.3 million each. The contingent payments are in effect should the average annual price of the Appalachia Dominion, South Point index exceed $3.30 per MMBtu in the individual annual periods from 2018 through 2020. 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 9. Long-Term Debt.

For the year ended December 31, 2017, we recognized a loss on divestiture of $2.3 billion, or $1.5 billion after-tax. The aggregate net book value of the properties sold was approximately $3.4 billion, which included approximately $883 million of undeveloped leasehold cost.

Production from the Marcellus Shale upstream assets represented 204 MMcfe/d of total consolidated sales volumes for the year ended December 31, 2017. See Supplemental Oil and Gas Information (Unaudited).

After the property sale, we retained certain firm transportation commitments to flow Marcellus Shale natural gas production. See Note 10. Marcellus Shale Firm Transportation Commitments.

Other US Onshore Transactions We conducted the following additional transactions in 2017:

- received total proceeds of $671 million resulting from the sale of certain US onshore properties, including $568 million related to divestment of non-core acreage in the DJ Basin. Proceeds were applied to reduce field basis with no recognition of gain or loss.
-

received $335 million and recognized a gain of $334 million on the sale of mineral and royalty assets covering approximately 140,000 net mineral acres concentrated primarily in Texas, Oklahoma and North Dakota.

- completed the acquisition of Delaware Basin properties, including seven producing wells, increasing our contiguous acreage position in the Reeves County area. Consideration totaled $301 million, approximately $246 million of which was allocated to undeveloped leasehold cost.

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

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

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

Noble Midstream Partners Advantage Joint Venture 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 approximately $67 million of cash to the Advantage 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. See Note 15. Equity Method Investments.

Noble Midstream Partners serves as operator of the Advantage Pipeline System, which includes a 70-mile crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150 MBbls per day of shipping capacity and 490 MBbls of storage capacity.

Other Acquisitions and Divestitures During 2017, we closed on the acquisition of other smaller US onshore properties for total cash consideration of $26 million. We also closed the sale of certain other smaller US onshore and international properties and received total cash consideration of $39 million, recording a loss of $6 million.

Year Ended December 31, 2016

Termination of Marcellus Shale JDA In fourth quarter 2016, we and CONSOL Energy Inc. (CONSOL) agreed to terminate our 50-50 Joint Development Agreement (JDA) in the Marcellus Shale. In connection with the terminated JDA, we executed and closed an exchange agreement whereby we and CONSOL each transferred all of our interest in a portion of co-owned properties to one another. In addition to the acreage and production realignment between the two companies, we remitted a cash payment of approximately $213 million to CONSOL at closing. Terminating the JDA resulted in the elimination of the remaining outstanding carried cost obligation due from us. No gain or loss was recognized on the exchange.

DJ Basin Acreage Exchange We closed a cashless acreage exchange in the DJ Basin receiving approximately 11,700 net acres within our Wells Ranch development area in exchange for approximately 13,500 net acres primarily from our Bronco area. No gain or loss was recognized.

2016 Divestitures During 2016, we engaged in the following sales transactions:

- entered an agreement to divest certain producing and non-producing properties covering approximately 33,100 net acres in the DJ Basin for proceeds of $505 million. We closed the sale on a portion of the properties in 2016, receiving proceeds of $486 million, with the remainder of the sale closing in 2017. Proceeds were applied to reduce field basis with no recognition of gain or loss;
- sold additional DJ Basin non-producing properties, certain Eagle Ford properties, our Bowdoin property in northern Montana, and certain other smaller US onshore properties, generating total net proceeds of $152 million, a net loss of $23 million on the Bowdoin sale, and no further gain or loss recognized on the remaining transactions;
- sold our 47% interest in the Alon A and Alon C licenses, which included the Karish and Tanin fields, offshore Israel, for a total sales price of $73 million ($67 million for asset consideration and $6 million from cost adjustments). Proceeds were applied to reduce field basis with no recognition of gain or loss;
- sold a 3.5% working interest in the Tamar and Dalit fields, offshore Israel, in compliance with the terms of the Framework, which requires us to reduce our ownership interest in the fields to 25% by year-end 2021. The sales price totaled $431 million, and we received net cash proceeds of $316 million, after consideration of timing and tax adjustments, at closing. Proceeds were ratably applied to the fields basis and resulted in the recognition of a $261 million gain; and
- received proceeds of $131 million related to the farm-out of a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, offshore Cyprus. We received the remaining proceeds of $40 million in January 2017. Proceeds were applied to reduce field basis with no recognition of gain or loss.

Other Divestitures During 2016, we also closed the sale of certain smaller US onshore properties and received total cash consideration of $83 million, with no recognition of gain or loss.

See Supplemental Oil and Gas Information (Unaudited) for discussion of proved reserves added or divested in connection with the above transactions.

Note 6. Goodwill Impairment

As of December 31, 2017 and through September 30, 2018, our consolidated balance sheet included goodwill of $1.4 billion, of which $1.3 billion, resulting from the Clayton Williams Energy Acquisition, was allocated to our Texas reporting unit, included within our oil and gas exploration and production segment, and $110 million was allocated to our Midstream reporting unit. We conducted our annual goodwill impairment assessment as of September 30, 2018. At that time, we concluded that goodwill was not impaired.

In fourth quarter 2018, we considered changes to facts and circumstances, particularly the decline in WTI strip pricing, increase in operating and capital costs, as well as our development plan, and concluded that it was more likely than not that the fair value of our Texas reporting unit was less than its carrying amount. For purposes of determining the goodwill impairment, we estimated the implied fair value of the goodwill using a variety of valuation methods, including the income and market approaches. Our estimate of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions for future crude oil and natural gas production, commodity prices based on forward commodity price curves, operating and development costs and other factors. The analysis indicated that the implied fair value of our Texas reporting unit goodwill was zero and we recognized a loss of $1.3 billion.

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, excluding amounts that were capitalized and subsequently expensed in the same period, are as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Capitalized Exploratory Well Costs, Beginning of Period	$520	$768	$1,353
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	7	20	84
Divestitures and Other [1]	(168)	—	(143)
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale [2]	(1)	(203)	(1)
Capitalized Exploratory Well Costs Charged to Expense [3]	(4)	(65)	(525)
Capitalized Exploratory Well Costs, End of Period	$354	$520	$768

(1) The 2018 amount represents costs primarily related to Gulf of Mexico assets sold during second quarter and the 2016 amount relates to the farm-down of a 35% interest in Block 12 offshore Cyprus to a new partner.

(2) The 2017 amount relates to the approval and sanction of the first phase of development of the Leviathan field.

(3) Capitalized exploratory well costs charged to expense are included within exploration or impairment expense in our consolidated statements of operations. The 2017 amount relates primarily to the write-off of costs associated with the Troubadour natural gas discovery, Gulf of Mexico, for which we chose not to pursue development activities. The 2016 amount relates primarily to discoveries offshore West Africa. Following review of additional 3D seismic data, we determined these discoveries were impaired in the current forward outlook for crude oil prices. We also incurred expenses associated with the Silvergate exploratory well, Gulf of Mexico, which did not encounter commercial hydrocarbons and was subsequently plugged and abandoned.

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

	December 31,		
(millions)	2018	2017	2016
Exploratory Well Costs Capitalized for a Period of One Year or Less	$6	$10	$69
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	348	510	699
Balance at End of Period	$354	$520	$768
	7	8	10

Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling

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The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of December 31, 2018:

Country/Project *(millions)*	Total	Suspended Since 2016 - 2017	2014 - 2015	2013 & Prior	**Progress**
Offshore Equatorial Guinea					
Felicita (Block O)	$48	$3	$ 7	$38	We are in process of evaluating regional development scenarios for this 2008 natural gas discovery. In early 2016, we began analyzing, interpreting and evaluating the acquired seismic data. In 2018, we progressed definitive agreements to sell natural gas through the Punta Europa plants, which will expand the options for additional natural gas sales.
Yolanda (Block I)	24	2	3	19	A data exchange agreement for the 2007 Yolanda condensate and natural gas discovery has been executed between the governments of Equatorial Guinea and Cameroon. Our development team is working with both governments to evaluate natural gas monetization options for both Yolanda and YoYo (Cameroon) discoveries. In 2018, we progressed the definitive agreements to sell natural gas through the Punta Europa plants, which will open the options for additional natural gas sales.
Offshore Cameroon					
YoYo (YoYo Block)	52	(1)	6	47	A data exchange agreement for the 2007 YoYo condensate and natural gas discovery has been executed between the governments of Equatorial Guinea and Cameroon. Our development team is working with both governments to evaluate natural gas monetization options for both Yolanda (Equatorial Guinea) and YoYo discoveries. In June 2017, we converted our mining concession license for the YoYo block into a PSC. In 2018, we progressed the definitive agreements to sell natural gas through the Punta Europa plants, which will open the options for additional natural gas sales.
Offshore Israel					
Leviathan-1 Deep	94	6	8	80	The well did not reach the target interval in 2012. In 2018, we continued to reprocess and review seismic information for this prospect, incorporating information obtained from other recent discoveries in the region and developing future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases.
Dalit	24	2	3	19	Our future development plan was approved by the Government of Israel to develop this 2009 natural gas discovery with a tie-in to existing infrastructure at Tamar. Currently, we are analyzing 3D seismic data to evaluate additional potential of the area.
Offshore Cyprus					
Cyprus	100	11	12	77	We continue to work with the Government of Cyprus to obtain approval of our development plan and the issuance of an Exploitation License. During 2017, we submitted an updated development plan. During 2018, we continued to progress capital project cost improvement and regional natural gas marketing efforts.
Other					
Projects less than $20 million	6	(7)	10	3	Continuing to assess and evaluate wells.
Total	$348	$16	$ 49	$283	

Undeveloped Leasehold Costs Undeveloped leasehold costs are derived from allocated fair values as a result of business combinations or other purchases of unproved properties and are subject to impairment testing. 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

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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.
Changes in undeveloped leasehold costs were as follows:

	December 31,	
(millions)	2018	2017
Undeveloped Leasehold Costs, Beginning of Period	$2,922	$2,197
Additions to Undeveloped Leasehold Costs [1]	47	1,859
Transfers to Proved Properties [2]	(453)	(174)
Assets Sold [3]	(142)	(884)
Impairment [4]	(1)	(62)
Other	—	(14)
Undeveloped Leasehold Costs, Net of Impairment, End of Period	$2,373	$2,922

(1) 2017 additions relate to the Clayton Williams Energy Acquisition and Delaware Basin asset acquisition.
(2) 2018 transfers relate primarily to Delaware Basin assets.
(3) 2017 sales relate primarily to the Marcellus Shale upstream divestiture.
(4) 2017 impairment expense was primarily attributable to Gulf of Mexico leases.

As of December 31, 2018, remaining undeveloped leasehold costs, to which proved reserves had not been attributed, totaled $2.4 billion, including $2.2 billion and $100 million attributable to Delaware Basin and Eagle Ford Shale, respectively.
The remaining balance of undeveloped leasehold costs as of December 31, 2018 included $53 million and $31 million related to international and domestic unproved properties, respectively. 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.

Note 8. Asset Retirement Obligations

ARO consists primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in ARO are as follows:

	Year Ended December 31,	
(millions)	2018	2017
Asset Retirement Obligations, Beginning Balance	$875	$935
Liabilities Incurred	25	94
Liabilities Settled	(345)	(82)
Revisions of Estimates	293	(65)
Reclassification to Liabilities Associated with Assets Held for Sale	(1)	(54)
Accretion Expense	33	47
Asset Retirement Obligations, Ending Balance	$880	$875

Year Ended December 31, 2018 Liabilities settled primarily included $216 million and $24 million of liabilities assumed by the purchasers of the Gulf of Mexico properties and Greeley Crescent assets, respectively, and $104 million related to abandonment of US onshore properties, primarily in the DJ Basin, where we have engaged in a program to plug and abandon older vertical wells. Costs associated with the DJ Basin abandonment activities will be incurred over several years.
Revisions of estimates were primarily related to increases in cost estimates and changes in timing estimates of $287 million for US onshore, primarily in the DJ Basin related to the abandonment activities noted above, $10 million for

wells offshore Israel and $9 million for wells offshore Equatorial Guinea, partially offset by decreases in cost and timing estimates of $17 million associated with the North Sea abandonment project.

Year Ended December 31, 2017 Liabilities incurred include $63 million related to the Clayton Williams Energy Acquisition and $31 million primarily for other US onshore wells and midstream facilities placed into service. Liabilities settled include $43 million related to abandonment of US onshore properties, $19 million related to properties sold in the Greeley Crescent (DJ Basin) acreage divestiture, $12 million related to properties sold in the Marcellus Shale upstream divestiture and $8 million related to other offshore domestic and international properties.

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Revisions of estimates include a $42 million decrease related to changes in cost and timing associated with the North Sea abandonment project and a $38 decrease for US onshore and Gulf of Mexico properties, partially offset by an increase of $15 million for West Africa.
In 2017, we also transferred $42 million and $12 million of ARO liabilities associated with Southwest Royalties and Tamar field, respectively, to liabilities associated with assets held for sale. See Note 5. Acquisitions and Divestitures.

Note 9. Long-Term Debt

Our debt consists of the following:

	December 31, 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	60	3.67 %	85	2.75 %
Noble Midstream Services Term Loan Credit Facility, due July 31, 2021	500	3.42 %	—	— %
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	223	— %	273	— %
Total	$6,675		$6,859	
Unamortized Discount	(22)		(24)	
Unamortized Premium [(1)]	—		12	
Unamortized Debt Issuance Costs	(38)		(40)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	$6,615		$6,807	
Less Amounts Due Within One Year:				
Capital Lease Obligations	(41)		(61)	
Long-Term Debt Due After One Year	$6,574		$6,746	

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

(2) Includes $8 million of 5.875% Senior Notes due June 1, 2024 and $84 million of 7.25% Senior Debentures due August 1, 2097.

All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest. The indenture documents of each of our notes provide that we may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually.

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

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The Revolving Credit Facility requires that our total debt to capitalization ratio (as defined in the Revolving Credit Facility), expressed as a percentage, not exceed 65% at any time. A violation of this covenant could result in a default under the Credit Agreement, which would permit the participating banks to restrict our ability to access the Revolving Credit Facility and require the immediate repayment of any outstanding advances under the Revolving Credit Facility. We were in compliance with our debt covenants as of December 31, 2018.

Certain lenders that are a party to the Revolving Credit Facility have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for us for which they have received, and may in the future receive, customary compensation and reimbursement of expenses.

In the first quarter 2018, we extended the maturity date of the Revolving Credit Facility from August 2020 to March 2023. As of December 31, 2018, no borrowings were outstanding under the Revolving Credit Facility.

Noble Midstream Services Revolving Credit Facility Noble Midstream Services LLC (Noble Midstream Services), a subsidiary of Noble Midstream Partners, maintains a revolving credit facility (Noble Midstream Services Revolving Credit Facility), which is available to fund working capital and to finance acquisitions and other capital expenditures of Noble Midstream Partners.

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.

The Noble Midstream Services Revolving Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated leverage ratio to consolidated adjusted earnings before interest expense, income taxes, depreciation, depletion, and amortization (EBITDA) and (2) consolidated interest coverage ratio (each covenant as described in the Noble Midstream Services Revolving Credit Facility). All obligations of Noble Midstream Services, as the borrower under the Noble Midstream Services Revolving Credit Facility, are guaranteed by Noble Midstream Partners and all wholly-owned material subsidiaries of Noble Midstream Partners. Debt issuance costs associated with this facility were de minimis.

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

In third quarter 2018, we used $480 million proceeds from the issuance of a new term loan credit facility to repay a portion of the balance outstanding under the Noble Midstream Services Revolving Credit Facility. See *Noble Midstream Services Term Loan Credit Facility,* below. As of December 31, 2018, $60 million was outstanding under the Noble Midstream Services Revolving Credit Facility.

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

Borrowings under the Noble Midstream Services Term Loan Credit Facility bear interest at a rate equal to, at Noble Midstream Partners' option, either (1) a base rate plus an applicable margin between 0.00% and 0.50% per annum or (2) a Eurodollar rate plus an applicable margin between 1.00% and 1.50% per annum. As of December 31, 2018, $500 million was outstanding under the Noble Midstream Services Term Loan Credit Facility.

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

Redemption of Senior Notes In May 2018, we redeemed $379 million of Senior Notes due May 1, 2021 that we assumed in the merger with Rosetta Resources, Inc. in 2015 for $395 million.

Senior Notes Issuance and Completed Tender Offer On August 15, 2017, we issued $600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and $500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. Interest on the 3.85% senior notes and 4.95% senior notes is payable semi-annually beginning January 15, 2018 and

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February 15, 2018, respectively. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. The senior notes were issued at a discount of $4 million and debt issuance costs incurred totaled $11 million, both of which are reflected as a reduction of long-term debt and are amortized over the life of the notes. Proceeds of $1.1 billion from the issuance of senior notes were used solely to fund the tender offer and the redemption of $1.1 billion of our 8.25% senior notes due March 1, 2019. As a result, we paid a premium of $96 million to the holders of the 8.25% senior notes and recognized a loss of $98 million in third quarter 2017, which is reflected in other non-operating (income) expense in our consolidated statements of operations.
Leviathan Term Loan Facility 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 provided for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to $1.0 billion, of which $625 million was initially committed. Any amounts borrowed under the Leviathan Term Loan Facility would have been available to fund a portion of our share of costs for the initial phase of development of the Leviathan field. No amounts were ever drawn on the facility, which was terminated in December 2018.
Fair Value of Debt See Note 14. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.
Capital Lease Obligations The amount of the capital lease obligation is based on the discounted present value of future minimum lease payments, and therefore does not reflect future cash lease payments. Amounts due within one year equal the amount by which the capital lease obligation is expected to be reduced during the next 12 months. See Note 11. Commitments and Contingencies for future capital lease payments.
Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments, as of December 31, 2018 are as follows:

(millions)	Debt Principal Payments
2019	$ —
2020	—
2021	1,500
2022	—
2023	160
Thereafter	4,792
Total	$ 6,452

Note 10. Marcellus Shale Firm Transportation Commitments

On June 28, 2017, we closed the sale of our Marcellus Shale upstream assets, which were primarily natural gas properties. In connection with the divestiture, we retained certain financial commitments on pipelines flowing natural gas production inside and outside of the Marcellus Basin. These financial commitments represent commitments to pay transportation fees; thus, we have no commitment to physically transport minimum volumes of natural gas.
Since closing, we have continued efforts to commercialize these firm transportation commitments including the permanent assignment of capacity, negotiation of capacity releases, utilization of capacity through purchase and transport of third-party natural gas, and other potential arrangements. In the event we execute a permanent assignment of capacity, we no longer have a contractual obligation to the pipeline company and, as such, our gross contractual commitment is reduced. In the event we execute a capacity release or utilize the capacity through the purchase and transport of third-party natural gas, we remain the primary obligor to the pipeline company. While our gross contractual commitment is not reduced, except through use under those arrangements, we would receive future cash payments from the third-parties with whom we negotiated a capacity release or from the sale of purchased natural gas to third-parties.

As of December 31, 2018, our gross retained firm transportation commitment for the remaining obligations under these agreements, which have remaining terms of approximately four to fifteen years, is approximately $1.5 billion, undiscounted. See Note 11. Commitments and Contingencies.

One of the retained contracts relates to the Texas Eastern Pipeline. This contract is being fully utilized through a capacity release agreement with the acquirer of the Marcellus Shale upstream assets. The financial commitment on this contract is being fully mitigated by a netback agreement with the purchaser.

One of the retained contracts relates to the Appalachian Gateway Project. In 2017, we recorded an exit cost of $41 million, discounted, related to this contract, as we no longer have production to satisfy the commitment and do not plan to utilize this capacity in the future.

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Additional retained contracts relate to the Leach Xpress and Rayne Xpress (Leach/Rayne Xpress) pipelines. In 2017, we permanently assigned a portion of the capacity, recording an exit cost of $52 million, discounted, related to future commitments to the third-party. Throughout 2018, we mitigated the impact of the remaining capacity through purchasing third-party natural gas and selling the natural gas to other third parties at prevailing market prices. Revenues and expenses associated with these activities are recorded on a gross basis, as we act as a principal in these arrangements by assuming control of the purchased commodity before it is transferred to the customer.

In addition to the retained firm transportation commitments, we also have the following accrued discounted liabilities associated with the exit cost activities described above:

	December 31,	
(millions)	2018	2017
Balance at Beginning of Period	$90	$—
Marcellus Exit Cost Accrual	—	93
Payments, Net of Accretion	(10)	(3)
Balance at End of Period	$80	$90
Less Current Portion Included in Other Current Liabilities	13	14
Long-term Portion Included in Other Noncurrent Liabilities	$67	$76

Two additional retained contracts relate to the WB Xpress and NEXUS pipelines. In fourth quarter 2018, we entered into capacity release agreements with third parties extending through March and October 2020, respectively. Revenues and expenses associated with these agreements, as well as those associated with purchasing and selling third-party natural gas to mitigate Leach/Rayne Xpress capacity, are as follows:

		Year Ended December 31,		
(millions)	Statements of Operations Location	2018	2017	2016
Sales of Purchased Gas	Sales of Purchased Oil and Gas and Other	$113	$ —	$ —
Cost of Purchased of Gas	Other Operating Expense, Net	108	—	—
Utilized Firm Transportation Expense [1]	Other Operating Expense, Net	29	—	—
Unutilized Firm Transportation Expense	Other Operating Expense, Net	3	—	—
Cost of Purchased Gas, Total	Other Operating Expense, Net	$140	$ —	$ —

(1) Includes the net impact of the difference in the firm transportation contract rates and the rates agreed to in the capacity releases. Additionally, amount includes transportation expense associated with our transport of purchased natural gas on Leach/Rayne Xpress.

We expect to continue our commercialization actions, including utilizing pipeline capacity through purchases of third-party natural gas and sales to other third parties, to mitigate these firm transportation commitments. Some of our commercialization efforts may require pipeline and/or FERC approval to ultimately reduce the financial commitment associated with these contracts. If we determine that we will not utilize a portion, or all, of the contracted pipeline capacity, we will accrue a liability at fair value for the net amount of the estimated remaining financial commitment. We cannot guarantee our commercialization efforts will be successful and we may recognize substantial future liabilities. See Note 5. Acquisitions and Divestitures.

Subsequent Event In January 2019, we executed agreements on Leach/Rayne Xpress to permanently assign the remaining capacity to a third-party effective January 1, 2021 extending through the remainder of the contract term. The permanent assignment reduces our total undiscounted financial commitment under the Marcellus Shale firm transportation contracts by approximately $350 million. In January 2019, we recorded exit costs of $92 million, discounted, related to future commitments to the third-party. We will continue efforts to mitigate the impact of these transportation agreements during 2019 and 2020.

Note 11. 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.

Colorado Air Matter In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency (EPA), US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream crude oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the US District Court for the District of Colorado on June 2, 2015.

The Consent Decree, which alleges violations of the Colorado Air Pollution Prevention and Control Act and Colorado's federal approved State Implementation Plan, specifically Colorado Air Quality Control Commission Regulation Number 7, requires us to perform certain corrective actions, to complete mitigation projects, to complete supplemental environmental projects (SEP), and to pay a civil penalty. Costs associated with the settlement consist of $5 million in civil penalties which were paid in 2015. Mitigation costs of $4 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 $84 million, of which $77 million was incurred to undertake corrective actions at certain tank systems following the outcome of adequacy of design evaluations and certain operation and maintenance activities to handle potential peak instantaneous vapor flow rates. Future costs associated with injunctive relief are not yet precisely quantifiable as we are continually evaluating various approaches to meet the ongoing obligations of the Consent Decree.

Overall compliance with the Consent Decree has resulted in the temporary shut-in and permanent plugging and abandonment of certain wells and associated tank batteries. Consent Decree compliance could result in additional temporary shut-ins and permanent plugging and abandonment of certain wells and associated tank batteries. The Consent Decree sets forth a detailed compliance schedule with deadlines for achievement of milestones through early 2019 that may be extended depending on certain situations. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that which is required under existing Colorado regulations.

We have concluded that the penalties, injunctive relief, plugging and abandonment activities, and mitigation expenditures that result from this settlement, based on currently available information will not have, a material adverse effect on our financial position, results of operations or cash flows. See Note 8. Asset Retirement Obligations.

Colorado Water Quality Control Division Matter In January 2017, we received a Notice of Violation/Cease and Desist Order (NOV/CDO) advising us of alleged violations of the Colorado Water Quality Control Act (Act) and its implementing regulations as it relates to our Colorado Discharge Permit System General Permit for construction activities associated with oil and gas exploration and/or production within our Wells Ranch Drilling and Production field located in Weld County, Colorado (Permit). The NOV/CDO further orders us to cease and desist from all violations of the Act, the regulations and the Permit and to undertake certain corrective actions. In October 2018, we met with enforcement staff at the Colorado Department of Public Health and Environment (CDPHE) to discuss a potential settlement of the alleged violations. Given the ongoing status of such settlement discussions, we are unable to predict the ultimate outcome of this action at this time but believe that the resolution of this action will not have a material adverse effect on our financial position, results of operations or cash flows.

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

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

Colorado Clean Water Act Referral Notice In September 2018, we received a letter from the US Department of Justice providing notification of referral from the EPA of alleged Clean Water Act violations at an upstream production facility and a midstream gathering facility in Weld County, Colorado. The letter requests an opportunity to discuss settlement of the alleged violations. Given the uncertainty associated with enforcement actions of this nature, we are unable to predict the ultimate outcome of this action at this time, but believe that the resolution of this action will not have a material adverse effect on our financial position, results of operations or cash flows.

Marcellus Shale Firm Transportation Obligations As part of our Marcellus Shale upstream divestiture, we retained certain transportation and gathering obligations to flow Marcellus Shale natural gas production to various markets inside and outside of the Marcellus Basin. See Note 10. Marcellus Shale Firm Transportation Commitments.

Other Transportation and Gathering Obligations We have transportation and gathering obligations to flow US onshore production, primarily in the DJ Basin, to various markets. Certain of these contracts require us to make payments for any

shortfalls in delivering or transporting minimum volumes under the commitments. As properties are undergoing development activities, we may experience temporary shortfalls until production volumes increase to meet or exceed the minimum volume commitments and will incur expense related to volume deficiencies and/or unutilized commitments. We expect to continue to incur expense related to deficiency and/or unutilized commitments in the near-term. These amounts are recorded as marketing expense in our consolidated statements of operations.
Our total financial commitment for these agreements, which have remaining terms of two to ten years, is approximately $612 million, undiscounted. The commitment is included in the table below.
Non-Cancelable Leases and Other Commitments We hold leases and other commitments for drilling rigs, buildings, equipment and other property. Rental expense for office buildings and oil and gas operations equipment was $90 million in 2018, $69 million in 2017, and $76 million in 2016.
Minimum commitments as of December 31, 2018 consist of the following:

(millions)	Purchase and Service Obligations	Marcellus Shale Firm Transportation and Other Obligations (1)	Gathering, Transportation & Processing Obligations	Operating Lease Obligations (2)	Capital Lease Obligations (2)	Total
2019	$ 197	$ 123	$ 151	$ 91	$ 52	$614
2020	29	122	129	74	46	400
2021	13	121	103	59	31	327
2022	6	118	67	62	22	275
2023	21	113	66	50	20	270
2024 and Thereafter	5	934	285	176	104	1,504
Total	$ 271	$ 1,531	$ 801	$ 512	$ 275	$3,390

(1) Amount includes exit cost obligations resulting from a permanent capacity assignment. See Note 10. Marcellus Shale Firm Transportation Commitments.

(2) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 9. Long-Term Debt.

Note 12. Income Taxes

Components of income (loss) from operations before income taxes are as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Domestic	$(953)	$(2,831)	$(1,859)
Foreign	1,093	640	87
Total	$140	$(2,191)	$(1,772)

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

	Year Ended December 31,		
(millions, except percentages)	2018	2017	2016
Current Taxes			
Federal	$22	$(11)	$(4)
State	2	1	5
Foreign	172	96	196
Total Current	$196	$86	$197
Deferred Taxes			
Federal	$(123)	$(1,258)	$(784)
State	(7)	(8)	(24)
Foreign	60	39	(176)
Total Deferred	$(70)	$(1,227)	$(984)
Total Income Tax Provision (Benefit) Attributable to Noble Energy	$126	$(1,141)	$(787)
Effective Tax Rate	90.0 %	52.1 %	44.4 %

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
(percentages)	2018	2017	2016
Federal Statutory Rate [1]	21.0 %	35.0 %	35.0 %
Effect of			
Goodwill Impairment	192.5	—	—
Change in Valuation Allowance [1]	(170.2)	(17.4)	(2.0)
US and Foreign Statutory Rate Change [1]	80.7	23.5	1.6
Accumulated Undistributed Foreign Earnings [1]	—	11.0	7.2
Transition Tax [1]	—	(4.8)	—
Difference Between US and Foreign Rates	17.9	1.8	(0.1)
Earnings of Equity Method Investees	(20.1)	1.9	1.0
Noncontrolling Interests	(12.1)	1.1	0.4
State Taxes, Net of Federal Benefit	0.9	0.3	1.3
Foreign Exploration Loss	(35.6)	—	—
Global Intangible Low-Taxed Income (GILTI) [1]	24.2	—	—
Return to Provision	(17.1)	(0.1)	(0.2)
Audit Settlement	5.1	0.1	(0.2)
Oil Profits Tax - Israel	3.3	(0.1)	—
Other, Net	(0.5)	(0.2)	0.4
Effective Rate	90.0 %	52.1 %	44.4 %

[1] See *Tax Reform Legislation* and *Accumulated Undistributed Earnings of Foreign Subsidiaries*, below.

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Deferred tax assets and liabilities resulted from the following:

	December 31,	
(millions)	2018	2017
Deferred Tax Assets		
Loss Carryforwards	$589	$902
Employee Compensation and Benefits	92	97
Mark to Market of Commodity Derivative Instruments	(27)	7
Foreign Tax Credits	138	366
Other	157	104
Total Deferred Tax Assets	$949	$1,476
Valuation Allowance - Foreign Loss Carryforwards and Foreign Tax Credits	(320)	(549)
Net Deferred Tax Assets	$629	$927
Deferred Tax Liabilities		
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(1,669)	(2,029)
Total Deferred Tax Liability	$(1,669)	$(2,029)
Net Deferred Tax Liability	$(1,040)	$(1,102)

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(millions)	2018	2017
Deferred Income Tax Asset - Noncurrent	$21	$25
Deferred Income Tax Liability - Noncurrent	(1,061)	(1,127)
Net Deferred Tax Liability	$(1,040)	$(1,102)

Tax Reform Legislation On December 22, 2017, the US Congress enacted 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. The SEC staff issued SAB 118 which allowed registrants to report provisional amounts for the income tax effects specific to Tax Reform Legislation for which accounting was incomplete but a reasonable estimate could be determined. We reported certain provisional amounts in fourth quarter 2017, some of which were adjusted in 2018 based on changes in estimates, including changes based on further guidance provided by the Internal Revenue Service (IRS).

Provisional amounts recorded in 2017 and changes in estimates reported in 2018 are as follows:

Remeasurement of Deferred Taxes In accordance with US GAAP, we recognized the effect of the rate change on deferred tax assets and liabilities in the period in which the tax rate change was enacted, resulting in the recognition of a provisional deferred tax benefit of $500 million at December 31, 2017. Further remeasurements of these deferred taxes in 2018 were associated with the return to provision resulted in a $10 million deferred tax benefit.

Transition Tax (Toll Tax) Tax Reform Legislation provided for a toll tax on a one-time “deemed repatriation” of accumulated foreign earnings for the year ended December 31, 2017. Based on early interpretations of the law, we recognized additional taxable income in 2017 of $767 million associated with the toll tax, which was fully offset by net operating losses (NOLs), and recorded corresponding deemed foreign tax credits of $164 million, against which we recorded a full valuation allowance.

On April 2, 2018, the US Department of the Treasury and the IRS released Notice 2018-26, signaling intent to issue regulations related to the toll tax for the year ended December 31, 2017. Notice 2018-26 clarified that an Internal Revenue Code Section 965(n) election is available with respect to both current and prior year NOLs. As a result, we released $252 million of the valuation allowance recorded against foreign tax credits to be utilized against the estimated $268 million toll tax liability recorded as of December 31, 2017. This resulted in a $252 million tax benefit and a corresponding expense of $107 million for the tax rate change adjustment on the previously utilized NOL's. The impact on first quarter 2018 total tax expense, related to this additional guidance, was a net $145 million discrete tax benefit.

During fourth quarter 2018, the toll tax calculations were finalized in conjunction with filing of the US tax return, resulting in a $261 million toll tax against which $240 million of foreign tax credits were utilized. This resulted in a $21 million liability payable in installments over eight years beginning in 2018. The additional impact recorded during fourth quarter 2018 was a net $5 million tax expense.

Global Intangible Low-Taxed Income (GILTI) Tax Reform Legislation also introduced a new tax on global intangible low-taxed income (GILTI). Further analysis and legal interpretation has resulted in identifying certain foreign oil related income (FORI) activity as GILTI income which will be offset by NOL carryforwards rather than the 50% deduction and related foreign tax credits. As a result of utilizing our NOL to offset the GILTI inclusion, we recognized tax expense of $34 million for 2018 GILTI associated with FORI from investments in operating assets in Equatorial Guinea and operations in Israel. We are making an accounting policy election to not record deferred taxes related to GILTI.

Other Provisions Tax Reform Legislation is a comprehensive bill containing other provisions that do not materially affect us. The ultimate impact may differ from our estimates if additional regulatory guidance is issued. We are closely monitoring the provision which revised and broadened the former Section 163(j) interest expense limitation rules. In tax years subsequent to 2021 the basis of the limitation calculation will change to be roughly equivalent to EBIT at which time we expect to be subject to an interest expense limitation. The interest expense not deducted due to limitation has an indefinite carryover period.

Deferred Tax Assets Our estimated pre-tax NOL carryforwards totaled approximately $2.4 billion at December 31, 2018, of which US federal income tax NOL carryforwards totaled approximately $1.7 billion and foreign NOL carryforwards were $670 million.

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

We currently have a valuation allowance on the deferred tax assets associated with foreign loss carryforwards and foreign tax credits. The valuation allowance on foreign loss carryforwards totaled $187 million and $183 million in 2018 and 2017, respectively. The valuation allowance on foreign tax credits totaled $132 million and $366 million in 2018 and 2017, respectively. As noted above, in first quarter 2018 we released $252 million of the valuation allowance recorded against the foreign tax credits and in fourth quarter 2018, we made further return to provision adjustments based on the tax return filing.

Clayton Williams Energy Acquisition On April 24, 2017, we completed the Clayton Williams Energy Acquisition. For federal income tax purposes, the transaction qualified as a tax free merger and we acquired carryover tax basis in Clayton Williams Energy's assets and liabilities. Our purchase price allocation is finalized and we recorded a deferred tax liability of $307 million, adjusted for the new US statutory rate, which includes a deferred tax asset for federal pre-tax NOLs of approximately $450 million. The merger resulted in a change of control for federal income tax purposes, and the NOL usage will be subject to an annual limitation in part based on Clayton Williams Energy's value at the date of the merger. We anticipate full utilization of the total NOL prior to expiration.

Effective Tax Rate Our effective tax rate increased in 2018 as compared with 2017, primarily due to the fourth quarter 2018 goodwill impairment for which there is no tax benefit and the deferred tax expense of $34 million for GILTI. This increase was reduced by a deferred tax benefit of $145 million recorded discretely in the current year, as discussed above, and a deferred tax benefit of $50 million associated with a write-off of foreign exploration losses. The increase in current income tax expense during 2018 as compared with 2017 is primarily due to foreign taxes on the gain recognized with the first quarter 2018 divestiture of a 7.5% working interest in the Tamar field. The decrease in deferred income tax benefit during 2018 as compared to 2017 is due to the significant deferred tax benefit recorded in 2017 associated with the revaluation of the US deferred tax liability at the reduced future tax rate.

Accumulated Undistributed Earnings of Foreign Subsidiaries During 2016, we reduced the deferred tax liability associated with unremitted foreign earnings, net of foreign tax credits, to $240 million. In 2017, as a result of Tax Reform Legislation, which established a new territorial tax regime, we reversed the deferred tax liability recorded in 2016, resulting in a deferred tax benefit of $240 million. As of December 31, 2018, there is no expected withholding tax impact upon actual distribution of earnings and as such, we have not recorded any tax associated with unremitted earnings.

Israeli Tax Law Effective December 21, 2016, the Israeli government decreased the corporate income tax rate from 25% to 24% for 2017 and from 24% to 23% effective January 2018. The full impact of the rate reduction was recognized in 2017, decreasing deferred tax expense by $12 million.

Furthermore, our Israeli operations are subject to the Natural Resources Profits Taxation Law, 2011 (the Law), which imposes a separate additional tax on profits from oil and gas activities (Oil Profits Tax). The Oil Profits Tax is calculated by dividing net accumulated revenue generated by each separate project by its cumulative investments as defined within the Law. Once the revenue factor (R Factor) reaches 1.5, a tax rate of 20% is imposed; as the ratio increases to a maximum of 2.3, the Oil Profits Tax increases progressively up to a maximum rate of 50%. The Oil Profits Tax provides for a corporate tax rate adjustment based on the corporate income tax rate, which is currently 23%. To the extent the corporate income tax rate exceeds 18%, a reduction in the Oil Profits Tax rate is calculated. At the current corporate tax rate, the Oil Profits Tax rate is 46.8%. The Oil Profits Tax is deductible for Israeli corporate tax purposes. Our Tamar and Leviathan projects are both subject to the Oil Profits Tax and are expected to pay at the maximum rate.

Unrecognized Tax Benefits We file a consolidated income tax return in the US federal jurisdiction, and we file income tax returns in various states and foreign jurisdictions. Our income tax returns are routinely audited by the applicable revenue authorities, and provisions are made in the financial statements for differences between positions taken in tax returns and amounts recognized in the financial statements in anticipation of audit results.

In our major tax jurisdictions, the earliest years remaining open to examination are: US - 2015, Israel - 2015 (2013 with respect to Israel Oil Profits Tax) and Equatorial Guinea - 2013. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. As of December 31, 2018 and 2017, we had no unrecognized tax benefits.

Note 13. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We may enter into crude oil and natural gas price hedging arrangements in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil and natural gas production. The derivative instruments we use may include variable to fixed price commodity swaps, enhanced swaps, collars and three-way collars, basis swaps, swaptions and/or put options.

The fixed price swap and collar contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a collar contract combined with a put option contract sold by us with a strike price below the floor price of the collar. We receive price protection at the purchased put option floor price of the collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

A swaption gives counterparties the right, but not the obligation, to enter into swap agreements with us on the option expiration dates.

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits during periods of increasing commodity prices.

See Note 14. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk, especially during periods of falling prices. Our commodity derivative instruments are currently with a diversified group of major banks or market participants. We monitor the creditworthiness of these counterparties and our internal hedge policies provide for exposure limits. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and could incur a loss.

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Unsettled Derivative Instruments As of December 31, 2018, we had entered into the following crude oil derivative instruments:

				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
2019	Swaps	NYMEX WTI	22,000	$ —	$ 56.96	$ —	$ —	$ —
2019	Three-Way Collars	NYMEX WTI	33,000	—	—	49.35	59.35	72.25
2019	Swaps	ICE Brent	5,000	—	57.00	—	—	—
2019	Three-Way Collars	ICE Brent	3,000	—	—	43.60	50.00	64.07
2019	Basis Swaps	[1]	27,000	(3.23)	—	—	—	—
2020	Swaption	NYMEX WTI	5,000	—	61.79	—	—	—
2020	Basis Swap	[1]	15,000	(5.01)	—	—	—	—

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

As of December 31, 2018, we had entered into the following natural gas derivative instruments:

				Swaps		Collars		
Settlement Period	Type of Contract	Index	MMBtu per Day	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
1Q19[1]	Swaps	NYMEX HH	86,500	$ —	$ 4.36	$ —	$ —	$ —
1Q19[1]	Three-Way Collars	NYMEX HH	21,500	—	—	3.00	3.25	4.08
2019	Three-Way Collars	NYMEX HH	104,000	—	—	2.25	2.65	2.95
2019	Basis Swaps	[2]	52,000	(0.74)	—	—	—	—

[1] We have entered into contracts for portions of 2019 resulting in the difference in hedged volumes for the full year.
[2] We have entered into natural gas basis swap contracts in order to establish a fixed amount for the differential between index pricing for Colorado Interstate Gas and NYMEX Henry Hub. The weighted average differential represents the amount of reduction to NYMEX Henry Hub prices for the notional volumes covered by the basis swap contracts.

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments on our consolidated balance sheets were as follows [1]:

	Asset Derivative Instruments				Liability Derivative Instruments			
	December 31, 2018		December 31, 2017		December 31, 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	$ 180	Current Assets	$ 2	Current Liabilities	$ 1	Current Liabilities	$ 58
	Noncurrent Assets	—	Noncurrent Assets	—	Noncurrent Liabilities	26	Noncurrent Liabilities	15
Total		$ 180		$ 2		$ 27		$ 73

(1) See Note 1. Summary of Significant Accounting Policies – Derivative Instruments and Hedging Activities.

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

	Year Ended December 31,		
(millions)	2018	2017	2016
Cash Paid (Received) in Settlement of Commodity Derivative Instruments			
Crude Oil	$162	$(14)	$(499)
Natural Gas	(1)	1	(70)
Total Cash Paid (Received) in Settlement of Commodity Derivative Instruments	161	(13)	(569)
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments			
Crude Oil	(225)	18	582
Natural Gas	1	(68)	126
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	(224)	(50)	708
(Gain) Loss on Commodity Derivative Instruments			
Crude Oil	(63)	4	83
Natural Gas	—	(67)	56
Total (Gain) Loss on Commodity Derivative Instruments	$(63)	$(63)	$139

Note 14. 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 on 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 considers market volatility, market prices and contract terms. See Note 13. Derivative Instruments and Hedging Activities.

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

Stock-Based Compensation Liability A portion of the value of the liability associated with our phantom unit plan is dependent upon the fair value of Noble Energy common stock as of the end of each reporting period. See Note 17. Stock-Based and Other Compensation Plans.

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

(millions)	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Adjustment [2]	Fair Value Measurement
December 31, 2018					
Financial Assets					
Mutual Fund Investments	$ 38	$ —	$ —	$ —	$ 38
Commodity Derivative Instruments	—	187	—	(7)	180
Financial Liabilities					
Commodity Derivative Instruments	—	(34)	—	7	(27)
Portion of Deferred Compensation Liability Measured at Fair Value	(43)	—	—	—	(43)
Stock Based Compensation Liability Measured at Fair Value	(8)	—	—	—	(8)
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) See Note 1. Summary of Significant Accounting Policies – Fair Value Measurements for a description of the fair value hierarchy.

(2) Amount represents the impact of netting clauses within our master agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis Certain assets and liabilities are measured at fair value on a nonrecurring basis on our consolidated balance sheets. See Note 1. Summary of Significant Accounting Policies for the methods and assumptions used to estimate the fair values:

Asset Impairments Impairments are recorded when we determine that the carrying amounts of certain oil and gas properties or midstream facilities are not recoverable from future cash flows, and are calculated using significant unobservable (Level 3) inputs. In 2018, upon classification of the Gulf of Mexico properties as assets held for sale, we recognized impairment expense of $168 million. Additionally, in fourth quarter 2018, we recorded impairment expense of $38 million, $37 million of which related to changes in construction plans for certain midstream assets. The 2017 impairment of $70 million primarily related to our decision not to pursue development of the Troubadour natural gas discovery in the Gulf of Mexico. The 2016 impairment of $92 million primarily related to a decision to write off certain development concepts associated with the Leviathan natural gas project that were not selected. The assets were reduced to their estimated fair values.

Inventory Impairment In 2016, we determined that the carrying amount of certain of our materials and supplies inventory was greater than its net realizable value, which was calculated using significant unobservable (Level 3) inputs. We recognized a $14 million impairment related to these assets.

Goodwill Impairment In fourth quarter 2018, we determined that the carrying amount of goodwill allocated to our Texas reporting unit was less than its estimated fair value, which was calculated using significant unobservable (Level 3) inputs. As a result, we recognized a goodwill impairment of $1.3 billion. See Note 6. Goodwill Impairment.

Marcellus Shale Firm Transportation Liability In 2017, we recorded liabilities totaling $93 million representing the discounted present value of our remaining obligation under certain firm transportation contracts. See Note 10. Marcellus Shale Firm Transportation Commitments.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public, fixed-rate debt to be a Level 1 measurement on the fair value hierarchy.

At December 31, 2018, our variable-rate, non-public debt included the Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility and the Noble Midstream Services Term Loan Credit Facility. 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 9. Long-Term Debt.

Fair value information regarding our debt is as follows:

(millions)	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$6,452	$6,121	$6,586	$7,142

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

Note 15. Equity Method Investments

Equity Method Investments Investments accounted for under the equity method consist primarily of the following:

- 50% interest in Advantage Pipeline, which owns and operates a 70-mile crude oil pipeline in Texas (See Note 5. Acquisitions and Divestitures);
- 45% interest in Atlantic Methanol Production Company, LLC (AMPCO), which owns and operates a methanol plant and related facilities in Equatorial Guinea; and
- 28% interest in Alba Plant , which owns and operates a LPG processing plant in Equatorial Guinea.

We consider these equity method investments essential components of our business as well as necessary and integral elements of our value chain in support of ongoing operations in our Midstream and West Africa segments. For the Advantage Pipeline system, Noble Midstream Partners serves as operator and exerts significant influence over the day-to-day operations. The operating agreements for Advantage Pipeline empower the board to direct activities that most significantly affect long-term economic performance. With regard to AMPCO, we hold a voting position on AMPCO's leadership team through AMPCO's management committee, and our asset teams influence decisions regarding capital investments, budgets, turnarounds, maintenance and other project matters. For the Alba Plant, our Alba asset teams are fully engaged in operational and financial decisions and exert significant influence in the monetization of the Alba field and Alba Plant.

Equity method investments are as follows:

(millions)	December 31, 2018	2017
Advantage Pipeline	$73	$70
AMPCO	131	129
Alba Plant	58	80
Other	24	26
Total Equity Method Investments	$286	$305

Additional Information At December 31, 2018, consolidated retained earnings included $68 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $13 million higher than the underlying net assets of the investee at December 31, 2018. The difference is related to capitalized interest which is being amortized into earnings over the remaining useful life of the plant.

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Summarized, 100% combined financial information for equity method investees is as follows:

(millions)	December 31, 2018	2017
Balance Sheet Information		
Current Assets	$387	$390
Noncurrent Assets	575	588
Current Liabilities	198	171
Noncurrent Liabilities	81	90

(millions)	Year Ended December 31, 2018	2017	2016
Statements of Operations Information			
Operating Revenues	$855	$790	$667
Operating Expenses	284	303	355
Operating Income	571	487	312
Other Income, net	3	15	7
Income Before Income Taxes	574	502	319
Income Tax Provision	152	136	60
Net Income	$422	$366	$259

Note 16. Additional Shareholders' Equity Information

Common Stock and Treasury Stock Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31, 2018	2017
Shares of Common Stock Issued		
Shares, Beginning of Period	528,743,381	471,360,427
Exercise of Common Stock Options	576,617	382,882
Restricted Stock Awarded, Net of Forfeitures [1]	2,488,363	2,912,936
Purchase and Retirement of Common Stock [2]	(10,008,128)	—
Shares Exchanged in Clayton Williams Energy Acquisition	(745,232)	54,087,136
Shares, End of Period	521,055,001	528,743,381
Treasury Stock		
Shares, Beginning of Period	38,786,969	37,961,316
Shares Received in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock [3]	267,258	1,026,891
Rabbi Trust Shares Distributed and/or Sold	(202,239)	(201,238)
Shares, End of Period	38,851,988	38,786,969
Additional Information		
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	—	—
Number of Antidilutive Stock Options, Shares of Restricted Stock and Shares of Common Stock in Rabbi Trust excluded from Dilutive Earnings (Loss) per Share [4]	15,004,591	15,619,276

(1) The 2017 amount includes approximately 1.9 million shares of restricted stock awarded to former holders of Clayton Williams Energy outstanding stock awards as part of the Clayton Williams Energy Acquisition.

(2) On February 15, 2018, we announced that the Company's Board of Directors had authorized a share repurchase program of $750 million which expires December 31, 2020. These shares were repurchased and retired at an average price of $29.49 per share.

(3) The 2017 amount includes approximately 720,000 shares of common stock received from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of Clayton Williams Energy restricted shares and options pursuant to the purchase and sale agreement.

(4) For the years ended December 31, 2018 and 2017, all outstanding options and non-vested restricted shares have been excluded from the calculation of diluted earnings (loss) per share as Noble Energy incurred a loss. Therefore, inclusion of outstanding options and non-vested restricted shares in the calculation of diluted earnings (loss) per share would be anti-dilutive.

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Accumulated Other Comprehensive Loss (AOCL) AOCL in the shareholders' equity section of the balance sheet included:

(millions)	Interest Rate Cash Flow Hedge	Other Postretirement Benefit Plans	Total
December 31, 2015	$ (22)	$ (11)	$ (33)
Realized Amounts Reclassified Into Earnings	1	4	5
Unrealized Change in Fair Value	—	(3)	(3)
December 31, 2016	(21)	(10)	(31)
Realized Amounts Reclassified Into Earnings	1	4	5
Unrealized Change in Fair Value	—	(4)	(4)
December 31, 2017	(20)	(10)	(30)
Realized Amounts Reclassified Into Earnings	(3)	1	(2)
Unrealized Change in Fair Value	—	—	—
December 31, 2018	$ (23)	$ (9)	$ (32)

Items in AOCL were initially recorded net of tax, using an effective income tax rate of 35%. In fourth quarter 2018, we reclassified to retained earnings approximately $6 million representing the effect of the decrease in the income tax rate to 21%.

AOCL at December 31, 2018 included deferred losses of $24 million, net of tax, related to an interest rate derivative instrument. This amount is reclassified to earnings as an adjustment to interest expense over the term of our senior notes due March 2041.

Note 17. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

(millions)	Year Ended December 31, 2018	2017	2016
Stock-Based Compensation Expense Included in:			
General and Administrative Expense	$54	$56	$62
Exploration Expense and Other	8	48	15
Total Stock-Based Compensation Expense	$62	$104	$77
Tax Benefit Recognized	$(13)	$(36)	$(27)

Stock Option and Restricted Stock Plans Our stock option and restricted stock plans are described below.

2017 Long-Term Incentive Plan On April 25, 2017, our shareholders approved the Noble Energy, Inc. 2017 Long-Term Incentive Plan (the 2017 Plan). Upon shareholder approval, the 2017 Plan superseded and replaced the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the 1992 Plan) which was frozen so that no future grants would be made under the 1992 Plan. The 1992 Plan continues to govern awards that were outstanding as of the date of its suspension, which remain in effect pursuant to their terms. Under the 2017 Plan, the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) may grant stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, stock awards and other incentive awards to our officers or other employees and those of our subsidiaries. The maximum number of shares that may be granted under the 2017 Plan is 29 million shares of common stock. At December 31, 2018, 26,621,632 shares of our common stock were reserved for issuance, including 21,084,928 shares available for future grants and awards, under the 2017 Plan.

Stock options are issued with an exercise price equal to the fair market value of our common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire 10 years from the grant date. Option grants generally vest ratably over a three-year period.

Restricted stock awards made under the 2017 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. During the period in which such restrictions apply, unless specifically provided otherwise in accordance with the terms of the 2017 Plan, the recipient of restricted stock would be the record owner of the shares and have all the rights of a shareholder with respect to the shares, including the right to vote and the right to receive dividends or other distributions made or paid with respect to the shares. The dividends or other distributions pertaining to the restricted shares will be held by the Company until the restriction period ends and the shares vest or forfeit. If the restricted shares forfeit, then the recipient shall not be entitled to receive the dividend or distribution, which will transfer to the Company.

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Restricted stock awards with a time-vested restriction vest over a two or three-year period. Performance share awards cliff vest after a three-year period if the Company achieves certain levels of total shareholder return relative to a pre-determined industry peer group.

2015 Stock Plan for Non-Employee Directors The 2015 Stock Plan for Non-Employee Directors of Noble Energy, Inc., as amended (the 2015 Plan) provides for grants of stock options and awards of restricted stock to our non-employee directors. The 2015 Plan superseded and replaced the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. The total number of shares of our common stock that may be issued under the 2015 Plan is 708,996. At December 31, 2018, 576,798 shares of our common stock were reserved for issuance, including 397,979 shares available for future grants and awards, under the 2015 Plan.

Stock Option Grants The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes-Merton option valuation model that used the assumptions described below:

- *Expected term* The expected term represents the period of time that options granted are expected to be outstanding, which is the grant date to the date of expected exercise or other expected settlement for options granted. The hypothetical midpoint scenario we use considers our actual exercise and post-vesting cancellation history and expectations for future periods, which assumes that all vested, outstanding options are settled halfway between the current date and their expiration date.
- *Expected volatility* The expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the expected term of the award. We use the historical volatility of our common stock for a period equal to the expected term of the option prior to the date of grant. We believe that historical volatility produces an estimate that is representative of our expectations about the future volatility of our common stock over the expected term.
- *Risk-free rate* The risk-free rate is the implied yield available on US Treasury securities with a remaining term equal to the expected term of the option. We base our risk-free rate on a weighting of five and seven year US Treasury securities as of the date of grant.
- *Dividend yield* The dividend yield represents the value of our stock's annualized dividend as compared to our stock's average price for the three-year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three-year period ended prior to the date of grant.

The assumptions used in valuing stock options granted were as follows:

	Year Ended December 31,		
(weighted averages)	2018	2017	2016
Expected Term (in Years)	6.7	6.4	6.3
Expected Volatility	33.4 %	33.2 %	32.4 %
Risk-Free Rate	2.6 %	2.2 %	1.6 %
Expected Dividend Yield	1.2 %	0.9 %	0.7 %
Weighted Average Grant-Date Fair Value	$10.47	$13.26	$10.10

Stock option activity was as follows:

	Options	Weighted Average Exercise Price *(per share)*	Weighted Average Remaining Contractual Term *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding at December 31, 2017	15,549,222	$ 43.42		

Granted	551,888	30.20			
Exercised	(576,617)	34.55			
Forfeited	(1,672,473)	40.04			
Outstanding at December 31, 2018	13,852,020	$ 44.04	5.0	$	—
Exercisable at December 31, 2018	11,866,188	$ 45.58	4.0	$	—

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The total intrinsic value of options exercised was $5 million in 2018, $4 million in 2017 and $10 million in 2016. As of December 31, 2018, $11 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.2 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards Awards of time-vested restricted stock (shares subject to service conditions) are valued at the price of our common stock at the date of award. The fair value of the market based restricted stock awards was estimated on the date of award using a Monte Carlo valuation model that uses the assumptions in the following table. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility represents the extent to which our stock price is expected to fluctuate between now and the award's anticipated term. We use the historical volatility of Noble Energy common stock for the three-year period ended prior to the date of award. The risk-free rate is based on a three-year period for US Treasury securities as of the year ended prior to the date of award.

The assumptions used in valuing market based restricted stock awards granted were as follows:

	Year Ended December 31,		
	2018	2017	2016
Number of Simulations	10,000,000	500,000	500,000
Expected Volatility	35 %	35 %	38 %
Risk-Free Rate	2.3 %	1.5 %	1.0 %

Restricted stock activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Shares	Weighted Average Award Date Fair Value *(per share)*	Number of Shares	Weighted Average Award Date Fair Value *(per share)*
Outstanding at December 31, 2017	1,839,737	$ 37.21	1,212,705	$ 25.55
Awarded	2,702,426	30.68	874,960	19.56
Vested	(982,280)	35.28	—	—
Forfeited	(386,992)	32.65	(702,031)	25.52
Outstanding at December 31, 2018	3,172,891	$ 32.72	1,385,634	$ 21.74

The total fair value of restricted stock that vested was $29 million in 2018, $34 million in 2017, and $24 million in 2016.

The weighted average award-date fair value of restricted stock awarded was $27.96 per share in 2018, $35.45 per share in 2017, and $29.99 per share in 2016.

As of December 31, 2018, $74 million of compensation cost related to all of our unvested restricted stock awarded under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.5 years. Common stock dividends accrue on restricted stock awards and are paid upon vesting. We issue new shares of our common stock when awarding restricted stock.

Cash-Settled Awards On February 1, 2016, we issued cash-settled awards to certain employees under the 1992 Plan in lieu of a portion of restricted stock and stock options. We issued approximately one million awards (so called phantom units, the nomenclature used in accounting literature), a portion of which are subject to the Company's achievement of certain levels of total shareholder return relative to a pre-determined industry peer group. The fair value of the market based phantom unit awards was estimated on the date of award using a Monte Carlo valuation model and assumed 500,000 simulations, 38% expected volatility and a risk-free rate of 0.9%.

These phantom units represent a hypothetical interest in the Company, and, once vested, are settled in cash. The phantom unit value at vesting will equal the lesser of the fair market value of a share of common stock of the Company as of the vesting date (two-year cliff vesting for officers and three-year cliff vesting for non-officers) or up to four times the fair market value of a share of common stock of the Company, which was $31.65, as of the grant date.

We accrued a liability of $8 million in 2018 related to the phantom units. No phantom units were awarded in 2018 or 2017.

Phantom unit activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Units	Weighted Average Award Date Fair Value *(per share)*	Number of Units	Weighted Average Award Date Fair Value *(per share)*
Outstanding at December 31, 2017	610,159	$ 31.65	167,483	$ 6.82
Vested	(83,276)	31.65	—	—
Forfeited	(59,518)	31.65	(17,187)	6.82
Outstanding at December 31, 2018	467,365	$ 31.65	150,296	$ 6.82

As of December 31, 2018, compensation cost related to phantom units remained to be recognized was de minimis. The remaining cost is expected to be recognized in first quarter 2019. The total fair value of phantom units that vested in 2018 was de minimis. Common stock dividends accrue on phantom units and are paid upon vesting.

Other Compensation Plans

401(k) Plan We sponsor a 401(k) savings plan. All regular employees are eligible to participate. We make contributions to match employee contributions up to the first 6% of compensation deferred into the plan, and certain profit sharing contributions for employees hired on or after May 1, 2006, based upon their ages and salaries. We made cash contributions of $31 million in 2018, $31 million in 2017, and $32 million in 2016.

Deferred Compensation Plan We have a non-qualified deferred compensation plan for which participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants in that nonqualified deferred compensation plan may elect to receive distributions in either cash or shares of our common stock. Components of that rabbi trust are as follows:

	December 31,	
(millions, except share amounts)	2018	2017
Mutual Fund Investments	$ 38	$ 57
Noble Energy Common Stock (at Fair Value)	5	14
Total Rabbi Trust Assets	$ 43	$ 71
Liability Under Related Deferred Compensation Plan	$ 43	$ 71
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	267,792	420,030

Assets of that rabbi trust, other than our common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds have published market prices and are reported at fair value. See Note 14. Fair Value Measurements and Disclosures. The mutual funds are included in the mutual fund investments account in other noncurrent assets in the consolidated balance sheets.

Shares of our common stock held by the rabbi trust holding common stock are accounted for as treasury stock (recorded at cost, $16.72 per share) in the shareholders' equity section of the consolidated balance sheets. Amounts payable to plan participants are included in other noncurrent liabilities in the consolidated balance sheets and include the market value of the shares of our common stock.

Approximately 200,000 shares, or 75%, of our common stock held in respect of one nonqualified deferred compensation plan at December 31, 2018 were attributable to a member of our Board of Directors. The remaining shares will be distributed in 2019. Distributions of 200,000 shares were made in each of 2018, 2017 and 2016. In addition, plan participants sold 2,239 shares of our common stock in 2018, 1,238 shares in 2017, and 1,009 shares in 2016. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $18 million in 2018, $21 million in 2017 and $22 million in 2016.

All fluctuations in market value of the deferred compensation liability have been reflected in other non-operating (income) expense, net in the consolidated statements of operations. We recognized deferred compensation expense of $2 million in 2018, $9 million in 2017 and $11 million in 2016.

We also maintain other nonqualified deferred compensation plans for the benefit of certain of our employees. Deferred compensation liabilities of $104 million and $116 million were outstanding at December 31, 2018 and 2017, respectively, under those other plans.

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In accordance with US GAAP for disclosures about oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures about our crude oil, NGL and natural gas reserves and exploration and production activities. The results of operations, costs incurred and capitalized costs associated with our Midstream reportable segment are not included in this disclosure.

Reserves There are numerous uncertainties inherent in estimating quantities of proved crude oil, NGL and natural gas reserves and reserves engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil, NGL and natural gas that are ultimately recovered. Economic producibility of reserves is dependent on the crude oil, NGL and natural gas prices used in the reserves estimate. We based our December 31, 2018, 2017, and 2016 reserves estimates on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, commodity prices are volatile and declines in crude oil, NGL and natural gas prices could result in negative reserves revisions. Production, development and abandonment costs are based on year-end economic conditions; therefore increases in these costs could also result in negative reserves revisions. Alternatively, decreases in these costs could result in positive reserves revisions.

Reserves Estimates Estimates of our proved reserves and associated future net cash flows are made solely by our engineers and are the responsibility of management. For additional information regarding our reserves estimation process and internal controls see Items 1. and 2. Business and Properties – Internal Controls Over Reserves Estimates and Technologies Used in Reserves Estimation.

Third-Party Reserves Audit We retained Netherland, Sewell & Associates, Inc. (NSAI), independent, third-party petroleum engineers, to perform a reserves audit of proved reserves as of December 31, 2018. See Items 1. and 2. Business and Properties – Proved Reserves Disclosures.

Definitions The following definitions apply to the terms used in the paragraphs above:

Reserves Estimate The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Reserves Audit The process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

The following definitions apply to our categories of proved reserves:

Proved Oil and Gas Reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to produce the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Developed Oil and Gas Reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Undeveloped Oil and Gas Reserves PUDs are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

For complete definitions of proved reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

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Proved Oil Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved crude oil reserves**:**

	Crude Oil and Condensate (MMBbls)			
	United States	Equatorial Guinea	Israel	Total
Proved Reserves as of:				
December 31, 2015	256	48	3	307
Revisions of Previous Estimates	14	(4)	—	10
Extensions, Discoveries and Other Additions	66	—	—	66
Sale of Minerals in Place	(4)	—	—	(4)
Production	(36)	(10)	—	(46)
December 31, 2016	296	34	3	333
Revisions of Previous Estimates	29	2	—	31
Extensions, Discoveries and Other Additions	104	—	6	110
Purchase of Minerals in Place	43	—	—	43
Sale of Minerals in Place	(12)	—	—	(12)
Production	(41)	(7)	—	(48)
December 31, 2017	419	29	9	457
Revisions of Previous Estimates	(31)	3	—	(28)
Extensions, Discoveries and Other Additions	98	3	—	101
Sale of Minerals in Place	(24)	—	(1)	(25)
Production	(42)	(6)	—	(48)
December 31, 2018	420	29	8	457
Proved Developed Reserves as of:				
December 31, 2015	137	34	3	174
December 31, 2016	138	34	3	175
December 31, 2017	176	29	3	208
December 31, 2018	165	26	2	193
Proved Undeveloped Reserves as of:				
December 31, 2015	119	14	—	133
December 31, 2016	158	—	—	158
December 31, 2017	243	—	6	249
December 31, 2018	255	3	6	264

Revisions of Previous Estimates Oil revisions included:

- *Price Revisions*

2016 positive price revisions included 19 MMBbls in the US and 4 MMBbls in Equatorial Guinea.
2017 positive price revisions included 12 MMBbls in the US.
2018 positive price revisions of 14 MMBbls included 10 MMBbls in the US and 4 MMBbls in Equatorial Guinea.

- *Non-Price Revisions*

2016 US revisions associated with positive performance and/or decreases in development or operating costs included revisions of 33 MMBbls in the DJ Basin, Marcellus Shale, Delaware Basin and Gulf of Mexico.
2017 US revisions associated with positive performance totaled 17 MMBbls, of which 14 were primarily attributable to the Delaware Basin due to continued optimization of well development and improved producing well performance.
2018 includes negative non-price revisions of 42 MMBbls, which primarily includes 30 MMBbls for changes in expected recoveries and increased operating and capital costs in the Delaware Basin, and 11 MMBbls for changes in the previously adopted development plan in the Eagle Ford Shale and DJ Basin.

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Extensions, Discoveries and Other Additions Oil extensions, discoveries and other additions included:

- 2016 extensions in US reserves included 38 MMBbls in the DJ Basin and 28 MMBbls in the Delaware Basin and Eagle Ford Shale, and was associated with increased performance from our horizontal drilling programs.
- 2017 extensions in US reserves included additions of 59 MMBbls in the Delaware Basin, 42 MMBbls in the DJ Basin and 3 MMBbls in the Eagle Ford Shale primarily due to the addition of planned new locations and activity.
- 2018 extensions relate to drilling plans for new wells and include 55 MMBbls, 38 MMBbls, 5 MMBbls and 3 MMBbls in the Delaware Basin, DJ Basin, Eagle Ford Shale and Equatorial Guinea, respectively.

Purchase of Minerals in Place The 2017 increase in oil was attributable to the reserves acquired in the Clayton Williams Energy Acquisition.

Sale of Minerals in Place Sales of oil minerals in place included:

- 2017 includes the sale of Marcellus Shale upstream assets and other non-strategic US onshore assets.
- 2018 sales included 16 MMBbls related to our Gulf of Mexico assets and 8 MMBbls related to other non-strategic US onshore assets.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures and Note 5. Acquisitions and Divestitures.

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Proved NGL Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved NGL reserves**:**

	NGLs (MMBbls)		
	United States	Equatorial Guinea	Total
Proved Reserves as of:			
December 31, 2015	176	13	189
Revisions of Previous Estimates	16	1	17
Extensions, Discoveries and Other Additions	31	—	31
Purchase of Minerals in Place	4	—	4
Production	(20)	(2)	(22)
December 31, 2016	207	12	219
Revisions of Previous Estimates	31	1	32
Extensions, Discoveries and Other Additions	32	—	32
Purchase of Minerals in Place	7	—	7
Sale of Minerals in Place	(38)	—	(38)
Production	(21)	(2)	(23)
December 31, 2017	218	11	229
Revisions of Previous Estimates	21	—	21
Extensions, Discoveries and Other Additions	48	—	48
Sale of Minerals in Place	(7)	—	(7)
Production	(23)	(2)	(25)
December 31, 2018	257	9	266
Proved Developed Reserves as of:			
December 31, 2015	101	5	106
December 31, 2016	113	12	125
December 31, 2017	119	11	130
December 31, 2018	121	9	130
Proved Undeveloped Reserves as of:			
December 31, 2015	75	8	83
December 31, 2016	94	—	94
December 31, 2017	99	—	99
December 31, 2018	136	—	136

Revisions of Previous Estimates NGL revisions included:

- *Price Revisions*

2016 included negative price revisions of 4 MMBbls.
2017 included positive price revisions of 6 MMBbls.
2018 included include positive price revisions of 5 MMBbls in the US.

- *Non-Price Revisions*

2016 US revisions were primarily associated with positive performance revisions of 11 MMBbls in the Marcellus Shale and 9 MMBbls in the DJ Basin.
2017 US revisions associated with positive performance revisions totaled 25 MMBbls, including 11 MMBbls in the Delaware Basin, 8 MMBbls in the Eagle Ford Shale and 6 MMBbls in the DJ Basin, due to continued optimization of well development and improved producing well performance.
2018 net positive non-price revisions of 16 MMBbls include positive revisions of 35 MMBbls in the DJ Basin primarily due to ASC 606 adoption, offset by negative revisions of 15 MMBbls in the Eagle Ford Shale due to changes in the previously adopted development plan and 4 MMBbls in the Delaware Basin for changes in expected

recoveries and increased operating and capital costs.

Extensions, Discoveries and Other Additions NGL extensions, discoveries and other additions included:

- 2016 extensions in US reserves primarily included an increase of 15 MMBbls in the DJ Basin and 14 MMBbls in the Delaware Basin and Eagle Ford shale due to improved well performance and/or decreases in development or operating costs.
- 2017 extensions in US reserves included 19 MMBbls in the DJ Basin, 9 MMBbls in the Delaware Basin and 4 MMBbls in the Eagle Ford Shale primarily due to the addition of planned new locations and activity.
- 2018 extensions relate to the addition of planned new locations and activity, of which 25 MMBbls, 15 MMBbls and 8 MMBbls relate to the DJ Basin, Delaware Basin and Eagle Ford Shale, respectively.

Sale of Minerals in Place Sales of NGL minerals in place included:

- 2017 sales included the Marcellus Shale upstream assets and other non-strategic US onshore assets.
- 2018 sales included 1 MMBbl from Gulf of Mexico assets and 6 MMBbls for certain non-core US onshore assets.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures and Note 5. Acquisitions and Divestitures.

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Proved Gas Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (Bcf)			
	United States	Israel	Equatorial Guinea	Total
Proved Reserves as of:				
December 31, 2015	2,711	2,304	534	5,549
Revisions of Previous Estimates	181	(3)	38	216
Extensions, Discoveries and Other Additions	492	—	—	492
Sale of Minerals in Place	(224)	(214)	—	(438)
Production	(322)	(103)	(86)	(511)
December 31, 2016	2,838	1,984	486	5,308
Revisions of Previous Estimates	124	292	13	429
Extensions, Discoveries and Other Additions	299	3,271	—	3,570
Purchase of Minerals in Place	46	—	—	46
Sale of Minerals in Place	(1,264)	—	(1)	(1,265)
Production	(222)	(99)	(87)	(408)
December 31, 2017	1,821	5,448	411	7,680
Revisions of Previous Estimates	1	2	22	25
Extensions, Discoveries and Other Additions	373	68	2	443
Sale of Minerals in Place	(79)	(502)	—	(581)
Production	(172)	(86)	(78)	(336)
December 31, 2018	1,944	4,930	357	7,231
Proved Developed Reserves as of:				
December 31, 2015	1,813	1,879	247	3,939
December 31, 2016	1,817	1,600	486	3,903
December 31, 2017	983	1,793	411	3,187
December 31, 2018	929	1,295	355	2,579
Proved Undeveloped Reserves as of:				
December 31, 2015	898	425	287	1,610
December 31, 2016	1,021	384	—	1,405
December 31, 2017	838	3,655	—	4,493
December 31, 2018	1,015	3,635	2	4,652

Revisions of Previous Estimates Gas revisions included:

- *Price Revisions*

2016 included negative commodity price revisions of 81 Bcf in the US and 20 Bcf in Equatorial Guinea.
2017 included positive commodity price revisions of 53 Bcf in the US and 13 Bcf in Equatorial Guinea.
2018 included positive price revisions of 44 Bcf in the US and 5 Bcf in Equatorial Guinea.

- *Non-Price Revisions*

2016 US revisions were primarily associated with positive performance and/or decreases in development or operating costs and included 167 Bcf in the Marcellus Shale and 95 Bcf in the DJ Basin. Equatorial Guinea revisions were associated with positive performance revisions of 58 Bcf at the Alba field.
2017 performance revisions of 66 Bcf primarily included 81 Bcf in the Eagle Ford Shale and 31 Bcf in the Delaware Basin, partially offset by negative performance revisions of 49 Bcf in the DJ Basin primarily associated vertical well locations.

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2018 net negative revisions of 24 Bcf include negative performance revisions of 43 Bcf in the US, partially offset by positive revisions of 19 Bcf in Equatorial Guinea and Israel. US includes positive revisions of 70 Bcf in the DJ Basin primarily due to ASC 606 adoption, offset by negative revisions of 71 Bcf in the Eagle Ford Shale due to changes in the previously adopted development plan and 42 Bcf primarily in the Delaware Basin due to changes in expected recoveries and increased operating and capital costs. Additional reserves of 17 Bcf in Equatorial Guinea and 2 Bcf in Israel relate to improved recoveries on existing wells.

Extensions, Discoveries and Other Additions Gas extensions, discoveries and other additions included:

- 2016 extensions in US reserves included positive performance revisions associated with our horizontal drilling programs including 230 Bcf in the Marcellus Shale, 185 Bcf in the DJ Basin, and 77 Bcf in the Delaware Basin and Eagle Ford Shale.
- 2017 extensions in US reserves included additions of 224 Bcf in the DJ Basin, 53 Bcf in the Delaware Basin and 22 Bcf in the Eagle Ford Shale primarily due to the addition of planned new locations and activity. The 2017 increase in Israel reserves represented sanction of the first phase of development of the Leviathan natural gas project.
- 2018 extensions in reserves relate to drilling plans for new wells. Increases in the US include 254 Bcf, 77 Bcf and 42 Bcf in the DJ Basin, Delaware Basin and Eagle Ford Shale, respectively, and the increase in Israel of 68 Bcf relates to the Tamar field.

Sale of Minerals in Place Sales of gas minerals in place included:

- 2016 included the sale of non-strategic US onshore assets, an acreage exchange in the Marcellus Shale where we relinquished 185 Bcf, and we sold a 3.5% ownership interest in the Tamar field, offshore Israel.
- 2017 included the sale of our Marcellus Shale upstream assets and other non-strategic US onshore assets.
- 2018 sales included 20 Bcf for our Gulf of Mexico assets, 59 Bcf for other non-strategic US onshore assets and 502 Bcf for a 7.5% working interest in the Tamar field, offshore Israel.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures and Note 5. Acquisitions and Divestitures.

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Supplemental Oil and Gas Information (Unaudited)

Results of Operations for Oil and Gas Producing Activities (Unaudited) Results of operations for crude oil and natural gas producing activities within the E&P reporting segments are as follows:

(millions)	United States	Israel	Equatorial Guinea	Other Int'l	Total
Year Ended December 31, 2018					
Revenues	$3,590	$480	$ 543	$—	$4,613
Production Costs [1]	1,276	37	110	2	1,425
Exploration Expense	48	2	1	78	129
DD&A	1,642	60	115	2	1,819
Loss (Gain) on Divestitures, Net [2]	36	(376)	—	—	(340)
Asset Impairments [3]	169	—	—	—	169
Marketing Expense	40	—	—	—	40
Gain on Asset Retirement Obligation Revisions	—	(8)	—	(17)	(25)
Income (Loss) before Income Taxes	379	765	317	(65)	1,396
Income Tax Expense [4]	80	176	79	—	335
Results of Operations [5]	$299	$589	$ 238	$(65)	$1,061
Year Ended December 31, 2017					
Revenues	$3,156	$534	$ 370	$—	$4,060
Production Costs [1]	1,199	49	103	2	1,353
Exploration Expense	102	—	1	85	188
DD&A	1,739	76	146	4	1,965
Loss on Marcellus Shale Upstream Divestiture and Other [6]	2,286	—	—	—	2,286
Asset Impairments [3]	63	—	—	7	70
Marketing Expense	47	—	—	—	47
Gain on Asset Retirement Obligation Revisions	—	—	—	(42)	(42)
(Loss) Income before Income Taxes	(2,280)	409	120	(56)	(1,807)
Income Tax (Benefit) Expense [4]	(798)	98	30	—	(670)
Results of Operations [5]	$(1,482)	$311	$ 90	$(56)	$(1,137)
Year Ended December 31, 2016					
Revenues	$2,416	$540	$ 433	$—	$3,389
Production Costs [1]	1,108	49	118	1	1,276
Exploration Expense [7]	245	26	469	185	925
DD&A	2,103	81	205	6	2,395
Asset Impairments [3]	—	88	—	4	92
(Loss) Income before Income Taxes	(1,040)	296	(359)	(196)	(1,299)
Income Tax (Benefit) Expense [4]	(364)	74	(90)	—	(380)
Results of Operations [5]	$(676)	$222	$ (269)	$(196)	$(919)

(1) Production costs consist of lease operating expense, production and ad valorem taxes, royalty expense, transportation and gathering expense, and general and administrative expense supporting oil and gas operations.

(2) See Note 5. Acquisitions and Divestitures.

(3) 2018 asset impairments relate to the sale of our Gulf of Mexico assets.
2017 asset impairments relate primarily to the Gulf of Mexico Troubadour well.
2016 asset impairments relate to certain Leviathan development concept costs.

(4) Income tax expense is based upon respective corporate statutory tax rates. During 2018, 2017, and 2016, we incurred exploration expense in currently non-commercial other international locations; therefore, no tax benefit was included in income tax expense associated with other international as we could not conclude it was more likely than not that some portion or all of the deferred tax assets would be realized.

(5) Results of operations exclude the mark-to-market gain or loss on commodity derivative instruments, corporate activities and overhead and interest costs. See Note 13. Derivative Instruments and Hedging Activities.

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(6) Amount reflects reclassification of $93 million accrued exit costs for retained Marcellus Shale firm transportation commitments from our US oil and gas exploration and production reportable segment to our Corporate segment. See Note 1. Summary of Significant Accounting Policies, Note 3. Segment Information and Note 10. Marcellus Shale Firm Transportation Commitments.

(7) Equatorial Guinea exploration expense includes amounts related to the write off of costs associated with certain discoveries. See Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited)

Costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities associated with the E&P reporting segments. Costs incurred also include new AROs established in the current year, as well as changes to AROs resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells. Costs associated with activities of our Midstream segment and other corporate activities are not included.

(millions)	United States	Israel	Equatorial Guinea	Other Int'l (1)	Total
December 31, 2018					
Property Acquisition Costs					
Proved (2)	$—	$—	$ —	$—	$—
Unproved (2)	41	—	—	—	41
Exploration Costs (3)	58	12	10	73	153
Development Costs (4)	2,303	663	20	(16)	2,970
Total Consolidated Operations	$2,402	$675	$ 30	$57	$3,164
December 31, 2017					
Property Acquisition Costs					
Proved (2)	$839	$—	$ —	$—	$839
Unproved (2)	1,817	—	—	—	1,817
Exploration Costs (3)	59	6	4	90	159
Development Costs (4)	1,870	483	33	(39)	2,347
Total Consolidated Operations	$4,585	$489	$ 37	$51	$5,162
December 31, 2016					
Property Acquisition Costs					
Proved (2)	$—	$—	$ —	$—	$—
Unproved (2)	234	—	—	—	234
Exploration Costs (3)	264	26	25	44	359
Development Costs (4)	905	109	31	—	1,045
Total Consolidated Operations	$1,403	$135	$ 56	$44	$1,638

(1) Other International includes Newfoundland, Suriname (until November 2018), Falkland Islands (until December 2018), other new ventures and previous North Sea operations, which are in the process of being decommissioned.

(2) 2018 unproved property acquisition costs include US onshore undeveloped leasehold activity during the year.

2017 proved and unproved property acquisition costs include amounts allocated from the Clayton Williams Energy Acquisition and

Note 5. Acquisitions and Divestitures

2016 unproved property acquisition costs relate to the termination of the Marcellus Shale joint development agreement. See Note 5. Acquisitions and Divestitures.

(3) 2018 exploration costs relate primarily to seismic expense, drilling costs, and lease rentals.

2017 exploration costs primarily include capitalized interest on Gulf of Mexico projects and $7 million dry hole cost related to the Araku-1 exploration well, offshore Suriname. The remainder relates to seismic expense and drilling costs.

2016 exploration costs include $44 million drilling and completion costs in the Gulf of Mexico.

(4) Worldwide development costs include amounts spent to develop PUDs of approximately $1.0 billion in 2018, $1.2 billion in 2017, and $656 million in 2016.

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US development costs include an increase of $302 million in ARO due primarily to upward revisions in 2018, a decrease of $17 million in 2017 and an increase of $20 million in 2016.
Israel development costs for 2018 include $646 million related to initial development of the Leviathan field. Israel development costs for 2017 include $416 million related to initial development of the Leviathan field and $63 million related to the Tamar 8 development well.
Israel development costs for 2016 relate primarily to development of the Tamar discovery. Israel development costs include increases in ARO of $13 million in 2018 and $4 million in 2017.
Equatorial Guinea development costs are de minimis in 2018, relate to the Alba field unitization project in 2017 and drilling and well completion and installation and construction of a compression platform in the Alba field in 2016. 2017 development costs include an increase in ARO of $14 million.
Other International development costs include decreases in ARO of $40 million in 2017 primarily associated with the North Sea abandonment project.

Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited) Aggregate capitalized costs relating to crude oil and natural gas producing activities within the E&P reporting segments are as follows:

	December 31,	
(millions)	2018	2017
Unproved Oil and Gas Properties [1]	$2,321	$2,978
Proved Oil and Gas Properties [2]	24,955	26,111
Total Oil and Gas Properties	27,276	29,089
Accumulated DD&A	(10,867)	(12,538)
Net Capitalized Costs	$16,409	$16,551

(1) Unproved oil and gas property costs at December 31, 2018 include previous acquisition costs of $2.2 billion related to Delaware Basin properties and $100 million related to Eagle Ford Shale properties.
Unproved oil and gas property costs at December 31, 2017 include previous acquisition costs of $2.7 billion related to Delaware Basin properties and $149 million related to Eagle Ford Shale properties.
(2) Proved oil and gas properties at December 31, 2018 include asset retirement costs of $966 million and assets held for sale of $133 million.
Proved oil and gas properties at December 31, 2017 include asset retirement costs of $941 million and assets held for sale of $448 million.

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(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited) The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows in accordance with US GAAP. The standards require the use of a 10% discount rate. This information is not the fair value, nor does it represent the expected present value of future cash flows of our proved oil and gas reserves.

(millions)	United States	Israel [1]	Equatorial Guinea	Other Int'l [2]	Total
December 31, 2018					
Future Cash Inflows [3]	$38,542	$27,559	$ 2,528	$—	$68,629
Future Production Costs [4]	(14,793)	(2,478)	(1,180)	—	(18,451)
Future Development Costs [5]	(5,793)	(1,038)	(170)	(32)	(7,033)
Future Income Tax Expense [6]	(2,061)	(12,185)	(277)	—	(14,523)
Future Net Cash Flows	15,895	11,858	901	(32)	28,622
10% Annual Discount for Estimated Timing of Cash Flows	(6,493)	(8,037)	(158)	4	(14,684)
Standardized Measure of Discounted Future Net Cash Flows	$9,402	$3,821	$ 743	$(28)	$13,938
December 31, 2017					
Future Cash Inflows [3]	$30,061	$29,998	$ 2,028	$—	$62,087
Future Production Costs [4]	(11,020)	(2,517)	(932)	—	(14,469)
Future Development Costs [5]	(5,941)	(1,706)	(109)	(51)	(7,807)
Future Income Tax Expense	(948)	(13,088)	(216)	—	(14,252)
Future Net Cash Flows	12,152	12,687	771	(51)	25,559
10% Annual Discount for Estimated Timing of Cash Flows	(5,202)	(8,993)	(113)	7	(14,301)
Standardized Measure of Discounted Future Net Cash Flows	$6,950	$3,694	$ 658	$(44)	$11,258
December 31, 2016					
Future Cash Inflows [3]	$19,924	$10,159	$ 1,851	$—	$31,934
Future Production Costs [4]	(8,756)	(764)	(1,001)	—	(10,521)
Future Development Costs [5]	(4,813)	(725)	(83)	(100)	(5,721)
Future Income Tax Expense	(941)	(4,228)	(141)	—	(5,310)
Future Net Cash Flows	5,414	4,442	626	(100)	10,382
10% Annual Discount for Estimated Timing of Cash Flows	(2,308)	(2,329)	(84)	25	(4,696)
Standardized Measure of Discounted Future Net Cash Flows	$3,106	$2,113	$ 542	$(75)	$5,686

(1) In accordance with the Framework, we were required to reduce our ownership in the Tamar and Dalit fields from 36% to 25% by year-end 2021. During 2016, we reduced our ownership to 32.5% through the sale of a 3.5% interest. During 2018, we reduced our ownership to 25% through the sale of a 7.5% interest. Therefore, amounts at December 31, 2018 reflect a 25% interest while amounts at December 31, 2017 and 2016 reflect a 32.5% working interest. See Note 5. Acquisitions and Divestitures. The 2017 increase in the standardized measure of discounted future net cash inflows relates primarily to the sanction of the first phase of development of the Leviathan field.

(2) Other International represents North Sea abandonment costs.

(3) The standardized measure of discounted future net cash flows does not include cash flows relating to anticipated future methanol sales.

(4) Production costs include lease operating expense, production and ad valorem taxes, transportation expense and general and administrative expense supporting crude oil and natural gas operations.

(5) Future development costs include future abandonment costs for each location. See Note 8. Asset Retirement Obligations.

(6) Future income tax expense includes the effect of statutory tax rates and the impact of tax deductions, tax credits and allowances relating to our proved reserves. As of December 31, 2017, US future income tax expense includes the expected impact of the recent Tax Reform Legislation. As of December 31, 2018, 2017 and 2016, future income tax expense for Israel also includes the effect of estimated future profit levy taxes and changes to corporate income tax rates.

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Noble Energy, Inc.
Supplemental Oil and Gas Information (Unaudited)

Prices and Other Assumptions in Discounted Future Net Cash Flows (Unaudited) Future cash inflows are computed by applying a 12-month average commodity price, adjusted for location and quality differentials on a field-by-field basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	Israel	Equatorial Guinea	Total
December 31, 2018				
Average Crude Oil and Condensate Price per Bbl	$66.66	$63.94	$ 70.92	$66.88
Average Natural Gas Price per Mcf	2.17	5.49	0.27	4.34
Average NGL Price per Bbl	24.48	—	45.15	25.19
December 31, 2017				
Average Crude Oil and Condensate Price per Bbl	$47.81	$46.82	$ 53.12	$48.13
Average Natural Gas Price per Mcf	2.83	5.43	0.27	4.54
Average NGL Price per Bbl	22.32	—	37.23	23.02
December 31, 2016				
Average Crude Oil and Condensate Price per Bbl	$37.36	$36.05	$ 42.45	$37.87
Average Natural Gas Price per Mcf	2.07	5.07	0.27	3.02
Average NGL Price per Bbl	14.30	—	26.12	14.94

The discounted future net cash flows are computed using a 12-month average commodity price applied to our year-end quantities of proved reserves, unless contractual arrangements designate the price to be used. We performed a sensitivity of our discounted future net cash flows to reflect a price reduction to our 12-month average commodity price. We estimate that a 10% per Bbl reduction in the average price of crude oil and NGLs from the 12-month average price for 2018 would reduce the discounted future net cash flows before income taxes by approximately $1.6 billion and $0.3 billion, respectively. We estimate that a 10% per Mcf reduction in the average price of natural gas from the 12-month average price for 2018 would reduce the discounted future net cash flows before income taxes by approximately $0.9 billion.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil, NGL and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions. Future development costs include amounts that we expect to spend to develop PUDs of approximately $2.1 billion in 2019, $1.5 billion in 2020 and $1.1 billion in 2021.

Future income tax expense is computed by applying the appropriate year-end statutory tax rates to the estimated future pre-tax net cash flows relating to proved crude oil, NGL and natural gas reserves, less the tax bases of the properties involved. Future income tax expense gives effect to tax credits and allowances, but does not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

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Noble Energy, Inc.
Supplemental Oil and Gas Information (Unaudited)

Sources of Changes in Discounted Future Net Cash Flows (Unaudited) Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil, NGL and natural gas reserves are as follows:

	Year Ended December 31,		
(millions)	2018	2017	2016
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$11,258	$5,686	$6,628
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(3,190)	(2,674)	(2,230)
Net Changes in Prices and Production Costs [1]	2,327	2,436	(593)
Extensions, Discoveries and Improved Recovery, Less Related Costs	2,036	3,711	463
Changes in Estimated Future Development Costs	(738)	(537)	(373)
Development Costs Incurred During the Period	2,986	1,975	1,090
Revisions of Previous Quantity Estimates	(9)	1,462	364
Purchases of Minerals in Place [2]	—	423	161
Sales of Minerals in Place [3]	(1,873)	(643)	(951)
Accretion of Discount	1,538	778	919
Net Change in Income Taxes [4]	(11)	(1,669)	414
Change in Timing of Estimated Future Production and Other	(386)	310	(206)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	$2,680	$5,572	$(942)
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$13,938	$11,258	$5,686

(1) The increases in 2018 and 2017 were driven primarily by higher 12-month average commodity prices.

(2) Purchase of minerals in 2017 relates to reserves acquired in the Clayton Williams Energy Acquisition.

(3) See Note 5. Acquisitions and Divestitures.

(4) The increase in 2018 future income tax expense relates primarily to the increase in US tax expense due to higher future taxable income and a reduction of NOL carryforwards utilized to offset future taxable income from $3.2 billion as of December 31, 2017 to $1.7 billion as of December 31, 2018. The increase is partially offset by a decrease in future taxes in Israel driven by the sale of 7.5% working interest in Tamar.

The increase in 2017 future income tax expense relates primarily to the increase in profit and levy taxes in Israel, partially offset by the decrease in future corporate income tax rate in Israel. The increase in profits tax is driven by a significant increase in future cash flows related to the Leviathan project sanctioning in 2017. The increase in US tax expense due to the increase in future taxable income was offset by the decrease in tax expense associated with utilization of future net operating losses and decrease in applicable tax rate from 35% to 21% due to the changes in the US Tax Law effective January 1, 2018.

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Noble Energy, Inc.
Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended March 31,	June 30,	Sep 30,	Dec 31,	Total
(millions except per share amounts)					
2018 [(1)] [(3)]					
Revenues	$1,286	$1,230	$1,273	$1,197	$4,986
Income (Loss) Before Income Taxes	543	10	307	(720)	140
Net Income (Loss) Including Noncontrolling Interests	574	(6)	248	(802)	14
Less: Net Income Attributable to Noncontrolling Interests	20	17	21	22	80
Net Income (Loss) Attributable to Noble Energy	554	(23)	227	(824)	(66)
Net Income (Loss) Per Share, Basic	1.14	(0.05)	0.47	(1.72)	(0.14)
Net Income (Loss) Per Share, Diluted	1.14	(0.05)	0.47	(1.71)	(0.14)
2017 [(2)] [(3)]					
Revenues	$1,036	$1,059	$960	$1,201	$4,256
Income (Loss) Before Income Taxes	59	(2,334)	(208)	292	(2,191)
Net Income (Loss)	47	(1,498)	(115)	516	(1,050)
Less: Net Income Attributable to Noncontrolling Interests	11	14	21	22	68
Net Income (Loss) Attributable to Noble Energy	36	(1,512)	(136)	494	(1,118)
Net Income (Loss) Per Share, Basic	0.08	(3.20)	(0.28)	1.01	(2.38)
Net Income (Loss) Per Share, Diluted	0.08	(3.20)	(0.28)	1.01	(2.38)

(1) First quarter 2018 included the following:

- $376 million pre-tax gain on sale of 7.5% working interest in Tamar field. See Note 5. Acquisitions and Divestitures;
- $196 million pre-tax gain on sale of our 50% interest in CONE Gathering. See Note 5. Acquisitions and Divestitures;
- $168 million impairment expense related to Gulf of Mexico asset divestiture. See Note 5. Acquisitions and Divestitures;
- $145 million discrete tax benefit, net, related to changes in federal income tax regulations. See Note 12. Income Taxes; and
- $79 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $51 million. See Note 13. Derivative Instruments and Hedging Activities.

Second quarter 2018 included the following:

- $249 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instrument of $184 million. See Note 13. Derivative Instruments and Hedging Activities; and
- $109 million gain on sale of 7.5 million CNX Midstream Partners units. See Note 5. Acquisitions and Divestitures.

Third quarter 2018 included the following:

- $198 million gain on sale of 14.2 million CNX Midstream Partners units. See Note 5. Acquisitions and Divestitures; and
- $155 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $88 million. See Note 13. Derivative Instruments and Hedging Activities.

Fourth quarter 2018 included the following:

- $1.3 billion goodwill impairment charge. See Note 6. Goodwill Impairment;
- $546 million gain on commodity derivative instruments, including non-cash portion of gain on commodity derivative instruments of $547 million. See Note 13. Derivative Instruments and Hedging Activities; and
- $38 million impairment expense primarily related to midstream assets. See Note 14. Fair Value Measurements and Disclosures.

(2) First quarter 2017 included the following:

- No unusual or infrequent activity.

Second quarter 2017 included the following:

- $2.3 billion loss on Marcellus Shale upstream divestiture. See Note 5. Acquisitions and Divestitures.

Third quarter 2017 included the following:

- $98 million loss on extinguishment of debt. See Note 9. Long-Term Debt.

Fourth quarter 2017 included the following:

- $270 million deferred tax benefit, net, related to changes in federal income tax regulations; and
- $334 million gain on sale of mineral and royalty assets. See Note 5. Acquisitions and Divestitures.

(3) The sum of the individual quarterly earnings (loss) may not agree with year-to-date earnings (loss) as each quarterly computation is based on the earnings (loss) for the individual quarter as reported with rounding applied.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures were effective and provide an effective as of December 31, 2018.

Management's Annual Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Management's Report on Internal Control over Financial Reporting, included in Item 8. Financial Statements and Supplementary Data.

The independent auditor's attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting), included in Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control over Financial Reporting

There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

Effective, February 15, 2019, the Board of Directors of Noble Energy, Inc. (the "Company") approved the amendment and restatement of the Company's By-Laws ("By-Laws"). The revision to the By-Laws included an amendment to Article III, Section 1(b) to allow for a Lead Independent Director, who attains the age of 72 as of the next annual meeting succeeding such person's 72nd birthday, to be eligible to stand for election as a director for one additional year, but ineligible to be appointed as the lead independent director.

The foregoing description of the amendment to the By-Laws is qualified in its entirety by reference to the full text of the By-Laws, a copy of which is filed as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated herein by reference.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as a part of this report:

(1) Financial Statements: The consolidated financial statements and related notes, together with the reports of KPMG LLP, Independent Registered Public Accounting Firm, appear in Part II, Item 8, Financial Statements and Supplementary Data, of this Form 10-K.

(2) Financial Statement Schedules: All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instruction or are inapplicable and, therefore, have been omitted.

(3) Exhibits: The exhibits listed below on the Index to Exhibits are filed or incorporated by reference as part of this Form 10-K.

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INDEX TO 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 January 17, 2017 (File No. 001-07964) 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 to the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed May 11, 2015 (File No. 001-07964) 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 (File No. 001-07964) and incorporated herein by reference).
2.4	Purchase and Sale Agreement among Noble Energy, Inc. and HG Energy II Appalachia, LLC dated May 1, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 1, 2017) filed May 5, 2017 (File No. 001-07964) 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 July 28, 2016 (File No. 001-07964) and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. (as amended through February 15, 2019) filed herewith.
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 July 28, 2016 (File No. 001-07964) 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 July 28, 2016 (File No. 001-07964) and incorporated herein by reference).
4.1	Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 24, 2009) filed February 27, 2009 (File No. 001-07964) and incorporated herein by reference).
4.2	Second Supplemental Indenture dated as of February 18, 2011, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 6.000% Notes due 2041 (including the form of 2041 Notes) (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 15, 2011) filed February 22, 2011 (File No. 001-07964) and incorporated herein by reference).
4.3	Third Supplemental Indenture dated as of December 8, 2011, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 4.15% Notes due 2021 (including the form of 2021 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: December 5, 2011) filed December 8, 2011 (File No. 001-07964) and incorporated herein by reference).
4.4	Fourth Supplemental Indenture dated as of November 8, 2013, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 5.25% Notes due 2043 (including the form of 2043 Notes) (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: November 5, 2013) filed November 8, 2013 (File No. 001-07964) and incorporated herein by reference).
4.5	Fifth Supplemental Indenture dated as of November 7, 2014, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 3.900% Notes due 2024 and 5.050% Notes due 2044 (including the forms of 2024 Notes and 2044 Notes) (filed as

	Exhibit 4.1 to the Registrant’s Current Report on Form 8-K (Date of Report: November 4, 2014) filed November 7, 2014 (File No. 001-07964) and incorporated herein by reference).
4.6	Sixth Supplemental Indenture dated as of July 29, 2015, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating the Registrant's 5.625% Notes due 2021, 5.875% Senior Notes due 2022 and 5.875% Notes due 2024 (including the forms of 2021 Notes, 2022 Notes and 2024 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: July 29, 2015) filed July 31, 2015 (File No. 001-07964) and incorporated herein by reference).
4.7	Seventh Supplemental Indenture dated as of August 15, 2017, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 3.850% Notes due 2028 and 4.950% Notes due 2047 (including the forms of 2028 Notes and 2027 Notes) (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K (Date of Report: August 15, 2017) filed August 15, 2017 (File No. 001-07964) and incorporated herein by reference).

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4.8	Indenture dated as of October 14, 1993 between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7.25% Notes Due 2023 (including the form of 2023 Notes) (filed in paper with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 on November 12, 1993 (File No. 001-07964) and incorporated herein by reference).
4.9	Indenture dated as of April 1, 1997 between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 on May 9, 1997 (File No. 001-07964) and incorporated herein by reference).
4.10	First Indenture Supplement dated as of April 2, 1997, to Indenture dated as of April 1, 1997, between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 8.00% Senior Notes Due 2027 (including the form of 2027 Notes) (filed with the SEC as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 on May 9, 1997 (File No. 001-07964) and incorporated herein by reference).
4.11	Second Indenture Supplement, dated as of August 1, 1997, to Indenture dated as of April 1, 1997, between the Registrant and US Trust Company of Texas, N.A. as trustee, relating to the Registrant's 7.25% Senior Debentures Due 2097 (including the form of 2097 Notes) (filed with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 on August 13, 1997 (File No. 001-07964) and incorporated herein by reference).
10.1	Credit Agreement, dated October 14, 2011, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, Bank of America, N.A., Mizuho Corporate Bank, LTD., and Morgan Stanley MUFG Loan Partners, LLC, as documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 14, 2011) filed October 18, 2011 (File No. 001-07964) and incorporated herein by reference).
10.2	Commitment Increase Agreement (Existing Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: September 28, 2012), filed October 2, 2012 (File No. 001-07964) and incorporated herein by reference).
10.3	Commitment Increase Agreement (New Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: September 28, 2012), filed October 2, 2012 (File No. 001-07964) and incorporated herein by reference).
10.4	First Amendment to Credit Agreement, dated October 3, 2013, by and among Noble Energy, Inc., NBL International Finance B.V., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd. and DNB Bank ASA, New York Branch as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 3, 2013) filed October 9, 2013 (File No. 001-07964) and incorporated herein by reference).
10.5	Second Amendment to Credit Agreement, dated August 27, 2015, by and among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd. and DNB Bank ASA, New York Branch as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: August 27, 2015) filed August 31, 2015 (File No. 001-07964) and incorporated herein by reference).
10.6	Third Amendment to Credit Agreement, dated March 9, 2018, by and among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd., and DNB Bank ASA, New York Branch as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: March 9, 2018) filed March 12, 2018 (File No.

	001-07964) and incorporated herein by reference).
10.7*	Noble Energy, Inc. Retirement Restoration Plan dated effective as of January 1, 2009 (filed as Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).
10.8*	Amendment No. 1 to the Noble Energy, Inc. Retirement Restoration Plan, dated effective as of December 31, 2013 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).
10.9*	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-07964) and incorporated herein by reference).

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10.10*	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed in paper with the SEC as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K405 for the year ended December 31, 1995 on March 25, 1996 (File No. 001-07964) and incorporated herein by reference).
10.11*	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009 (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).
10.12*	2015 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (as amended and restated effective October 20, 2015) (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 (File No. 001-07964) and incorporated herein by reference).
10.13*	Form of Stock Option Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.14*	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.15*	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (as amended and restated effective October 20, 2015) (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 (File No. 001-07964) and incorporated herein by reference).
10.16*	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 (File No. 001-07964) and incorporated herein by reference).
10.17*	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 27, 2009) filed February 2, 2009 (File No. 001-07964) and incorporated herein by reference).
10.18*	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended and restated effective October 20, 2015) (filed as Exhibit 10.2 to Registrant's Quarterly report on Form 10-Q for the quarter ended September 30, 2015 (File No. 001-07964) and incorporated herein by reference).
10.19*	Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 1, 2005) filed February 7, 2005 (File No. 001-07964) and incorporated herein by reference).
10.20*	Form of Non-Qualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.24 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.21*	Form of Restricted Stock Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.25 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.22*	Form of Restricted Stock Agreement (three-year vested awards) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.26 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.23*	Form of Restricted Stock Agreement (performance-vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.27 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.24*	Form of Non-Qualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.25*	—

	Form of Restricted Stock Agreement (two-year time vested for non-PEO executive officers) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.26*	Form of Restricted Stock Agreement (two-year time vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.26 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016 (File No. 001-07964) and incorporated herein by reference).
10.27*	Form of Performance Award Agreement (3-year performance vested stock and cash) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).

10.28*	Form of Cash Award Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.29*	Form of Restricted Stock Agreement (three-year performance-vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.8 to the Registrant's Current Report on Form 8-K/A (Date of Report: January 25, 2016) filed February 4, 2016 (File No. 001-07964) and incorporated herein by reference).
10.30*	Noble Energy, Inc. 2017 Long-Term Incentive Plan (incorporated by reference to Appendix C to the Company's Definitive Proxy Statement on Schedule 14A filed on March 2, 2017 (File No. 001-07964) and incorporated herein by reference).
10.31*	Form of Restricted Stock Award (two-year vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.32*	Form of Restricted Stock Award (three-year vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.33*	Form of Stock Option Award under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.34*	Form of Performance Share Award under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.8 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.35*	Form of Restricted Stock Award (three-year time-vested officers) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 29, 2018) filed February 1, 2018 (File No. 001-07964) and incorporated herein by reference).
10.36*	Form of Restricted Stock Award (three-year cliff vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 29, 2018) filed February 1, 2018 (File No. 001-07964) and incorporated herein by reference).
10.37*	Form of Cash Award Agreement (three-year vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan filed herewith.
10.38*	Form of Restricted Stock Award (three-year time vested-40/40/20) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan filed herewith.
10.39*	Amendment to the Noble Energy, Inc. Change of Control Agreement dated effective February 1, 2011 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: February 1, 2011), filed February 4, 2011 (File No. 001-07964) and incorporated herein by reference).
10.40*	Form of Noble Energy, Inc. Change of Control Agreement (as amended effective January 1, 2008), (filed as Exhibit 10.41 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-07964) and incorporated herein by reference).
10.41*	Noble Energy, Inc. Change of Control Severance Plan for Executives, as amended and restated effective January 30, 2018 (filed as Exhibit 10.39 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.42*	Termination of Change of Control Agreement dated effective October 21, 2014 by and between Noble Energy, Inc. and David L. Stover (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 21, 2014) filed October 27, 2014 (File No. 001-07964) and incorporated herein by reference).
10.43*	Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates, Inc. Deferred Compensation Plan) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-07964) and incorporated herein by

	reference).
10.44*	Amendment No. 1 to the Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates, Inc. Deferred Compensation Plan), dated effective as of January 1, 2014 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).
10.45*	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2009) (filed as Exhibit 10.31 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).
10.46*	Amendment No. 1 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of January 1, 2014 (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).

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10.47*	Amendment No. 2 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of January 1, 2015 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-07964) and incorporated herein by reference).
10.48*	Amendment No. 3 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of August 1, 2016 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-07964) and incorporated herein by reference).
10.49	Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.50	Amendment No. 1 dated July 22, 2012 to the Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 001-07964) and incorporated herein by reference).
10.52	Support Agreement, dated as of January 13, 2017, by and among certain stockholders affiliated with Ares Management, LLC, Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 (File No. 001-07964) and incorporated herein by reference).
10.53	Agreement Not to Dissent, dated as of January 13, 2017, by and among Clayton W. Williams, Jr., Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 (File No. 001-07964) and incorporated herein by reference).
10.54	Agreement Not to Dissent, dated as of January 13, 2017, by and among The Williams Children's Partnership, Ltd., Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 (File No. 001-07964) and incorporated herein by reference).
10.55†	Noble Energy Mediterranean Ltd. Facility Agreement, dated February 24, 2017 by and between NEML Leviathan Finance Company LTD as Borrower and BNP Paribas, Credit Agricole Corporate and Investment Bank, ING Bank N.V. Natixis and Societe Generale London Branch as Mandated Lead Arrangers (filed as Exhibit 10.9 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (File No. 001-07964) and incorporated herein by reference).
10.56	Noble Energy, Inc. Short-Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (File No. 001-07964) and incorporated herein by reference).
10.57*	Separation and Release Agreement between Noble Energy, Inc. and Gary W. Willingham, Executive Vice President - Operations, effective as of October 26, 2018 (filed as Exhibit 10.1 to Amendment No. 1 to the Registrant's Current Report on Form 8-K (Date of Report: November 8, 2018) filed November 9, 2018 (File No. 001-07964) and incorporated herein by reference).
21.1	Subsidiaries, filed herewith.
23.1	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	Consent of Independent Petroleum Engineers and Geologists—Netherland, Sewell & Associates, Inc., filed herewith.
31.1	Certification of the Registrant's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 7241), filed herewith.
31.2	Certification of the Registrant's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 7241), filed herewith.

32.1	Certification of the Registrant's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 1350), filed herewith.
32.2	Certification of the Registrant's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 1350), filed herewith.
99.1	Report of Netherland, Sewell & Associates, Inc., filed herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document

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*	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.
†	Confidential treatment granted under Rule 24b-2 as to certain portions of this exhibit, which are omitted and filed separately with the Commission.

Item 16. Form 10-K Summary

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Summary.

GLOSSARY

In this report, the following abbreviations are used:

Bbl	Barrel
BBoe	Billion barrels oil equivalent
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BCM	Billion cubic meters
BOE	Barrels oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for natural gas is significantly less than the price for a barrel of crude oil. The price for a barrel of NGL is also less than the price for a barrel of crude oil.
Boe/d	Barrels oil equivalent per day
Btu	British thermal unit
FPSO	Floating production, storage and offloading vessel
GHG	Greenhouse gas emissions
GSPA	Gas Sales Purchase Agreement
HH	Henry Hub index
IDP	Integrated Development Plan
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbl/d	Thousand barrels per day
MBoe/d	Thousand barrels oil equivalent per day
Mcf	Thousand cubic feet
MMBbls	Million barrels
MMBoe	Million barrels oil equivalent
MMBtu	Million British thermal units
MMBtu/d	Million British thermal units per day
MMcf/d	Million cubic feet per day
MMcfe/d	Million cubic feet equivalent per day
MMgal	Million gallons
NGLs	Natural gas liquids
NYMEX	The New York Mercantile Exchange
OPEC	The Organization of Petroleum Exporting Countries
PSC	Production sharing contract
Tcf	Trillion cubic feet
	United States generally accepted accounting principles

US GAAP	
WTI	West Texas Intermediate index

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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:	February 19, 2019	By: /s/ David L. Stover David L. Stover, Chairman of the Board and Chief Executive Officer
Date:	February 19, 2019	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date:	February 19, 2019	By: /s/ Dustin A. Hatley Dustin A. Hatley, Vice President, Chief Accounting Officer and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ David L. Stover David L. Stover	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 19, 2019
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 19, 2019
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 19, 2019
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 19, 2019
/s/ Michael A. Cawley Michael A. Cawley	Director	February 19, 2019
/s/ Edward F. Cox Edward F. Cox	Director	February 19, 2019
/s/ James E. Craddock James E. Craddock	Director	February 19, 2019
/s/ Barbara J. Duganier Barbara J. Duganier	Director	February 19, 2019
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 19, 2019

/s/ Holli C. Ladhani Holli C. Ladhani	Director	February 19, 2019
/s/ Scott D. Urban Scott D. Urban	Director	February 19, 2019
/s/ William T. Van Kleef William T. Van Kleef	Director	February 19, 2019