Continuing Forward

2015 Annual Report

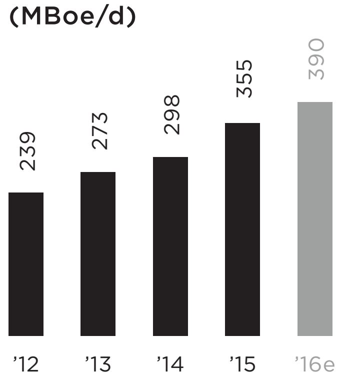
noble energy

"We have planned and structured this company to succeed in any market environment."

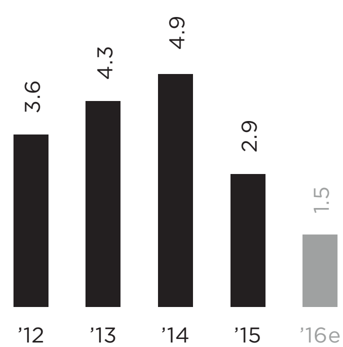
David L. Stover
Chairman, President and CEO

Moving forward with capital discipline.

SALES VOLUMES
(MBoe/d)

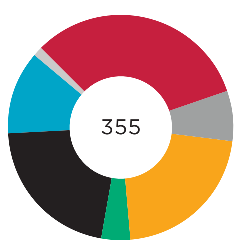


TOTAL CAPITAL
($Bn)

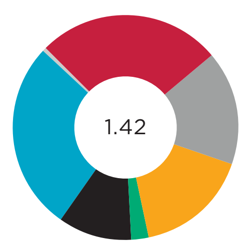


(Excludes merger and capital lease obligations)

2015 SALES VOLUMES
BY ASSET (MBoe/d)



2015 PROVED RESERVES
BY ASSET (BBoe)



DJ Basin
Texas
Marcellus Shale
Gulf of Mexico
West Africa
Eastern Mediterranean
Other

Message to Shareholders

Our early preparation, planning and actions provided us the clarity and confidence to manage and succeed in this environment.

Dear Fellow Shareholders,

For more than a decade, this company has planned and structured itself to succeed in any market environment. I am proud of what Noble Energy accomplished in 2015. With our diverse portfolio and a focus on areas core to the company, we continue to deliver outstanding results through a challenging commodity environment.

Our teams took action early in 2015, executing a strategy to manage capital within cash flows. This gave us the clarity and confidence to take advantage of opportunities, and it positions us well for the industry turnaround when that occurs.

Noble Energy started the year producing approximately 300 thousand barrels of oil equivalent per day and exited the year producing more than 400 thousand barrels of oil equivalent per day. We delivered this increase through both organic growth and the acquisition of premier assets, while materially reducing capital spending and total cash costs. We ended the year with total capital spend down more than 40 percent from the prior year and below forecast at a little less than $3 billion. Total cash costs were approximately 20 percent lower than 2014 on a per unit equivalent basis.

We created new capital efficiencies, especially in our onshore program, supporting returns and margin improvement in the business. For example, we cut controllable unit costs per barrel to their lowest level in eight years and materially upgraded performance in our core assets. Meanwhile, our offshore program remains a significant differentiator, generating strong cash flows for the business. We maintained our financial strength, exiting the year with $5 billion combined liquidity of cash on hand and available borrowings.

I'm pleased to report our business units delivered these results while setting a company safety record with the lowest recordable incident rate in our history. I don't believe it is a coincidence that outstanding operational and safety performance occurred in the same year. To me, it is an indication of the health of our business and the commitment of our employees.

2015 ACCOMPLISHMENTS

In the DJ Basin of Colorado, home to our largest onshore acreage and production, we enhanced value through innovation and efficiency gains, drilling longer laterals in less time, optimizing completion techniques and decreasing our overall average well costs approximately 30 percent year over year. Annual sales volumes averaged a record 115 thousand barrels of oil equivalent per day, with liquids an increasing share of the total volumes. Infrastructure expansion in the basin contributed to new production capacity, especially from our older vertical wells.

In July, we expanded our onshore portfolio with the Rosetta Resources Inc. merger, adding premier assets in Texas' two most prolific basins: the Permian and Eagle Ford. The merger delivers more than a billion barrels of oil equivalent potential to our portfolio and increased production by approximately 60 thousand barrels of oil equivalent per day. Our technical expertise from other U.S. basins, combined with Rosetta Resources' knowledge base, began paying off immediately with dramatic drill time reductions and completion improvements. Rosetta Resources' CEO, Jim Craddock, has joined Noble Energy's board of directors.

We set new records in the Marcellus with production volumes of more than 460 million cubic feet of natural gas equivalent per day on average for the year. With U.S. gas prices extremely challenged, we decided not to continue drilling and reduced activity. We ended 2015 with zero Marcellus rigs drilling and will focus our 2016 activity on completing a portion of our well inventory at a measured pace.

Offshore, in the Gulf of Mexico, we demonstrated our project execution proficiency by successfully bringing the Big Bend and Dantzler fields on line by the end of 2015 and quickly ramping up to a combined 20 thousand barrels of oil equivalent per day, net. Our Gunflint project is next, with first production targeted for mid-2016. Our exploration, appraisal, and development teams delivered remarkable performance, with these short-cycle, high-quality assets ahead of schedule and on budget. We estimate these successes will substantially increase our Gulf of Mexico production in 2016 and add to our track record of major project delivery.

Offshore West Africa, our operated Aseng and Alen projects continue to perform well, producing 24 thousand barrels of oil equivalent per day, net. A compression project at the non-operated Alba field will be completed in mid-2016 and will help sustain high production levels for that field. A 3D seismic program over our operated areas in Equatorial Guinea is under evaluation and could lead to new exploration opportunities or additional development.

In the Eastern Mediterranean, we created a tremendous amount of momentum during the year. Operationally, completing a compressor project ahead of summer demand, coupled with extraordinary uptime, allowed us to set new records for sales from our Tamar field of more than 250 million cubic feet per day, net for 2015. Gross volumes reached a billion cubic feet per day at times to meet high summer demand in Israel.

On the regulatory front, we were able to work with Israel's government to establish a natural gas framework to support future developments. It was approved by the Cabinet and supported by the Knesset. This framework establishes the regulatory certainty and stability necessary to proceed with our next phase of project developments. We'll spend 2016 completing gas sales contracts, securing project financing, and finalizing development scenarios to prepare the projects for final investment decisions.

The Eastern Mediterranean presents an opportunity to match our low-cost, abundant supply of natural gas with large regional demand. With the 10 trillion cubic feet Tamar field already on line, the 22 trillion cubic feet Leviathan field appraised and flow tested, and a discovery offshore Cyprus, we are well positioned to supply gas to the region for many years.

CONTINUING FORWARD

Our future is bright. We enter 2016 bolstered by strong liquidity, a repositioned cost structure, and the ability to manage within cash flow and protect our balance sheet. We are starting the year with a $1.5 billion capital program, which is a 50 percent reduction from last year. At the same time, our strong asset portfolio is expected to deliver approximately 390 thousand barrels of oil equivalent per day, an increase of 10 percent from 2015 reported volumes.

We now have four high-quality onshore core areas: DJ Basin, Eagle Ford, Permian (Delaware Basin), and Marcellus. All are low-cost assets. Coupled with our offshore core areas in West Africa, the Eastern Mediterranean, and the Gulf of Mexico, the company is able to build on a solid foundation with tremendous flexibility.

Our capital efficiency continues to improve dramatically, with contributions on all fronts. The diverse portfolio lets us focus capital on the best returns. New records in performance and optimizing completion results will further drive value improvement.

Our exploration plan is to drill two to three prospects in 2016 while we focus our capabilities on adding high-quality inventory to our portfolio. This environment provides the opportunity for our experienced staff to deepen our inventory at a relatively low cost of entry.

I expect great things in the coming year. We have an experienced leadership team, skilled managers and staff, and superb technical experts throughout our organization. Our core values and our vision of "Energizing the World, Bettering People's Lives" continue to drive our success.

I thank our shareholders who continue to entrust us with their confidence.

David L. Stover

David L. Stover
Chairman, President and CEO

Our Operations

Our diversified portfolio positions us for long-term success.

DJ BASIN

- Approximately 400,000 net acres in the liquids-rich portion of this premier U.S. oil play
- 2015 production: 115 MBoe/d
- Focusing activity in Wells Ranch and East Pony (combined approx. 100,000 acres)
- Maximizing efficiencies with long laterals, centralized infrastructure and enhanced completion designs

EAGLE FORD SHALE

- 50,000 net acres primarily in Dimmit and Webb Counties
- 2015 production: 53 MBoe/d*
- Leveraging onshore technical and operational expertise to materially improve efficiency and productivity

PERMIAN BASIN
(DELAWARE AND MIDLAND BASINS)

- 45,000 net acres in Reeves County and 9,000 net acres in Gaines County
- 2015 production: 8 MBoe/d*
- Well-positioned, oil-weighted acreage with multi-zone development potential
- First operated drilling and completion activity planned in 2016

MARCELLUS SHALE

- More than 350,000 net acres in leading U.S. natural gas play
- 2015 production: 462 MMcfe/d
- Focusing on completion activity and reducing capital and production costs

* Represents full-year production. Noble Energy acquired the Eagle Ford Shale and Permian Basin assets in the merger with Rosetta Resources Inc. in July of 2015.

GULF OF MEXICO

- Seven producing fields
- 2015 sales volumes: 15 MBoe/d
- Proven track record of exploration and development success
- Two new deepwater Gulf of Mexico fields, Big Bend and Dantzler, began production in the fourth quarter of 2015. A third field, Gunflint, is expected online in mid-2016
- Exploration and appraisal drilling planned in 2016

WEST AFRICA

- Offshore Equatorial Guinea, Cameroon and Gabon
- 2015 sales volumes: 76 MBoe/d (all in Equatorial Guinea)
- Maximizing production from Alba, Alen and Aseng fields
- Interpreting new 3D seismic over Equatorial Guinea blocks for potential exploration or development opportunities

EASTERN MEDITERRANEAN

- 1.3 million net acres offshore Israel and Cyprus
- Discovered gross resources: 40 Tcf
- 2015 sales volumes: 252 MMcfe/d (all in Israel)
- Negotiating gas sales contracts to supply gas to Israel and regional markets from Leviathan, Tamar and Aphrodite (Cyprus) fields

Financials

OPERATING DATA	2015	2014	2013	2012	2011
Year-end Proved Reserves					
Liquids (MMBbls)	**496**	432	435	357	369
Natural Gas (Bcf)	**5,549**	5,833	5,828	4,964	5,043
Total (MMBoe)	**1,421**	1,404	1,406	1,184	1,209
Sales Volumes from Continuing Operations					
Liquids (MBbl/d) [1]	**158**	133	123	109	78
Natural Gas (MMcf/d)	**1,187**	992	901	774	806
Total (MBoe/d)	**355**	298	273	239	213
Average Sales Price					
Crude Oil and Condensate (per Bbl) [2]	**$ 45.00**	$ 91.58	$ 100.29	$ 101.52	$ 99.17
Natural Gas (per Mcf)	**$ 2.44**	$ 3.38	$ 2.97	$ 2.19	$ 3.00

FINANCIAL DATA (In millions, except per share amounts and ratios)	2015	2014	2013	2012	2011
Revenues	**$ 3,133**	$ 5,101	$ 5,015	$ 4,223	$ 3,404
Income (Loss) from Continuing Operations	**$ (2,441)**	$ 1,214	$ 907	$ 965	$ 412
Net Income (Loss)	**$ (2,441)**	$ 1,214	$ 978	$ 1,027	$ 453
Income (Loss) from Continuing Operations per Share Diluted [3]	**$ (6.07)**	$ 3.27	$ 2.50	$ 2.68	$ 1.15
Net Income (Loss) per Share Diluted [3]	**$ (6.07)**	$ 3.27	$ 2.69	$ 2.86	$ 1.27
Weighted Average Shares Diluted [3]	**402**	367	363	359	357
Cash Dividends per Share [3]	**$ 0.72**	$ 0.68	$ 0.55	$ 0.45	$ 0.40
Net Cash Provided by Operating Activities	**$ 2,062**	$ 3,506	$ 2,937	$ 2,933	$ 2,170
Capital Expenditures [4]	**$ 2,852**	$ 4,883	$ 4,311	$ 3,626	$ 3,024
Total Assets	**$ 24,196**	$ 22,553	$ 19,642	$ 17,554	$ 16,444
Total Debt	**$ 7,976**	$ 6,197	$ 4,843	$ 4,123	$ 4,495
Shareholders' Equity	**$ 10,370**	$ 10,325	$ 9,184	$ 8,258	$ 7,265
Total Debt-to-Book-Capital Ratio	**43%**	38%	35%	33%	38%

[1] Includes sales from equity method investees

[2] Excludes equity method investees

[3] Amounts adjusted for the 2-for-1 stock split that occurred in 2013

[4] Excludes capital lease accruals and corporate acquisitions

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2015
or
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to
Commission file number: 001-07964

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State 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. ☒ Yes ☐ 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. ☐ Yes ☒ 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. ☒ Yes ☐ No

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

Indicate by check mark 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. ☒

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

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2015: $16.5 billion.

Number of shares of Common Stock outstanding as of December 31, 2015: 428,843,495.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2016 Annual Meeting of Stockholders to be held on April 26, 2016, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2015, are incorporated by reference into Part III.

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PART I

Items 1. and 2. Business and Properties

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Item 1A. Risk Factors.

General

Noble Energy, Inc. (Noble Energy, the Company, we or us) is a leading independent energy company engaged in worldwide crude oil, natural gas and natural gas liquids (NGLs) exploration and production. Founded in 1932, Noble Energy is a Delaware corporation, incorporated in 1969, and has been publicly traded on the New York Stock Exchange (NYSE) since 1980. We have a unique history of growth, evolving from a regional crude oil and natural gas producer to a global exploration and production company included in the Standard & Poor's 500 (S&P 500).

Our purpose, *Energizing the World, Bettering People's Lives®,* reflects our commitment to find and deliver energy through crude oil, natural gas and NGL exploration and production while living our commitment to contribute to the betterment of people's lives in the communities in which we operate. We strive to build trust through stakeholder engagement, act on our values, provide a safe work environment, respect our environment and care for our people and the communities where we operate.

We aim to achieve sustainable growth in value and cash flow through exploration success and the development of a high-quality, diversified portfolio of assets with investment flexibility between onshore unconventional developments and offshore organic exploration leading to major development projects. Our asset portfolio is further diversified between short-term and long-term projects, domestic and international and a balanced production mix among crude oil, natural gas and NGLs. In addition, occasional strategic acquisitions of producing and non-producing properties, combined with the periodic divestment of non-core assets, have allowed us to pursue our objective of a well-diversified, growing portfolio.

In particular, our organization and business models are focused on achieving sustainable, high-return growth through effective major development project execution complemented by pursuit of exploration opportunities that can be monetized on competitive discovery-to-production cycle times. Our ability to deliver major development projects on schedule and within budget has provided a competitive and financial advantage in our industry. In addition, the majority of our assets are held by production, which provides for investment and financial flexibility.

Impact of Current Commodity Prices on our Business The upstream oil and gas business is cyclical and we are currently operating in a period of low commodity prices. Commodity prices began declining sharply during fourth quarter 2014, continued to decline throughout 2015, and have been trading at multi-year lows thus far in 2016, with crude oil prices in particular falling below $30.00 per barrel on several occasions. During 2015, low commodity prices resulted in a reduction of our revenues, profitability, cash flows and proved reserves, asset and goodwill impairments, and reductions in our stock price, causing us to execute certain organizational changes. Continued decline in commodity prices in 2016 may result in additional impairments and cause further reduction in revenues, profitability, cash flows and proved reserves. In response to the low commodity prices, we reduced our capital spending program approximately 40%, as compared with 2014. See Item 1A. Risk Factors – *We are currently experiencing a severe downturn in the oil and gas business cycle, and an extended or more severe downturn could have material adverse effects on our results of operations, our liquidity, and the price of our common stock* and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments.

Operational Success Despite the negative financial impacts of the low commodity price environment, 2015 was a very successful year operationally. We directed our focus on the enhancement of onshore US completions, advancement of Eastern Mediterranean regional natural gas developments, development of our Gulf of Mexico crude oil discoveries and integration of two premier onshore US shale positions acquired through the Rosetta Merger, described below. Just as importantly, we achieved material reductions in capital and controllable unit costs, supporting project returns and margin improvements, and delivered year-over-year volume growth of almost 20% (or year-over-year organic volume growth of 10% excluding the addition of the Rosetta assets) resulting in record average sales volumes of 355 MBoe/d. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview and Results of Operations.

Positioning for the Future Throughout 2015 and into 2016, we have taken steps to sustain our business in the volatile and low commodity price environment that has evolved. We have adopted a comprehensive effort to spend within cash flow and manage the Company's balance sheet. To this end, we plan to defer certain activity to protect our liquidity position and have adopted a 2016 capital program more closely aligned with expected cash flow. In addition, our Board of Directors recently adjusted the quarterly dividend to 10 cents per common share, which represents a reduction of 8 cents, aligns the dividend yield with historical levels, and further enhances our liquidity. We also intend to reduce leverage in this environment and recently engaged in debt refinancing activities. The dividend reduction and debt refinancing are expected to provide approximately $200 million annually in support of balance sheet management efforts. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.

As we enter 2016, we believe we have positioned the Company for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. However, if the industry downturn continues for an extended period, or becomes more severe, we could experience additional material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and in response, we may consider further reductions in our capital program or dividends, asset sales or additional organizational changes. Our production and our stock price could decline further as a result of these potential developments. See Item 1A. Risk Factors – *We are currently experiencing a severe downturn in the oil and gas business cycle, and an extended or more severe downturn could have material adverse effects on our results of operations, our liquidity, and the price of our common stock.*

Oil and Gas Assets Onshore US assets provide a stable base of production along with low production-risk development programs. Our DJ Basin and Marcellus Shale assets, in particular, along with our recently-acquired Eagle Ford Shale and Permian Basin assets, have delivered significant historical production growth. Onshore US assets accommodate a flexible capital investment program that can be adjusted in response to ongoing changes in the economic environment and have the potential to deliver improved returns as supply and demand factors re-balance in the long term. We continue to enhance project performance through technology and operational efficiency.

Our long cycle offshore development projects, while requiring multi-year capital investment, offer sustained production, and are once again expected to offer attractive financial returns and sustained cash flow as supply and demand factors re-balance in the long term.

We have operations in seven core areas:

- the DJ Basin (onshore US)
- the Marcellus Shale (onshore US)
- Eagle Ford Shale (onshore US)
- Permian Basin (onshore US)
- the deepwater Gulf of Mexico (offshore US)
- offshore West Africa
- offshore Eastern Mediterranean

These seven core areas provide:

- almost all of our crude oil, natural gas and NGL production
- continual investment opportunities in proved areas
- exploration opportunities

In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy and its subsidiaries. All references to production, sales volumes and reserves quantities are net to our interest unless otherwise indicated.

Major Development Project Inventory We continue to advance a number of major development projects, many of which have resulted from our exploration success. Each project will progress, as appropriate, through the various development phases including appraisal, front-end engineering and design, development drilling, construction and production. We currently have projects in all phases of the development cycle with some contributing production growth in 2015 including, for example, our onshore US projects and the deepwater Gulf of Mexico Rio Grande field, which started production in the fourth quarter.

Although these projects will require significant capital investments over a multi-year period, they typically offer long-life, sustained cash flows and attractive financial returns over the oil and gas business cycle. Our current major development projects resulting from exploration success and strategic acquisitions include the following:

Sanctioned[(1)] Projects	Unsanctioned Projects
· DJ Basin (onshore US) [(2)]	· Tamar Expansion (offshore Israel) [(3)]
· Marcellus Shale (onshore US) [(2)]	· Leviathan (offshore Israel) [(3)]
· Eagle Ford Shale (onshore US) [(2)]	· Cyprus (offshore Cyprus)
· Permian Basin (onshore US) [(2)]	· Diega and Carla (offshore Equatorial Guinea)
· Gunflint (deepwater Gulf of Mexico)	· Katmai (deepwater Gulf of Mexico)
· Tamar Southwest (offshore Israel) [(3) (4)]	

(1) Final investment decision has been made.

(2) Represents multiple ongoing development projects.

(3) See Update on Israel – *Israel Natural Gas Framework*, below.

(4) Regulatory approval for the project has been delayed. Currently we are in an appeals process with the Israeli Ministry of National Infrastructures, Energy and Water Resources.

These projects are discussed in more detail in the sections below. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – Major Development Project Inventory.

Proved Oil and Gas Reserves Proved reserves at December 31, 2015 were as follows:

	December 31, 2015			
	Proved Reserves			
	Crude Oil and Condensate	Natural Gas	NGLs	Total
Reserves Category	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe) [1]
Proved Developed				
United States	137	1,813	101	540
Equatorial Guinea	34	247	5	81
Israel	3	1,879	—	315
Total Proved Developed Reserves	174	3,939	106	936
Proved Undeveloped				
United States	119	898	75	344
Equatorial Guinea	14	287	8	70
Israel	—	425	—	71
Total Proved Undeveloped Reserves	133	1,610	83	485
Total Proved Reserves	307	5,549	189	1,421

(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. See Item 6. Selected Financial Data.

Our proved reserves totaled 1,421 MMBoe as of December 31, 2015 as compared with 1,404 MMBoe as of December 31, 2014. Changes included the following:

- positive revisions of 91 MMBoe;
- extensions and other additions of 100 MMBoe related to our onshore US horizontal drilling programs; and
- additions of 269 MMBoe related to our acquisition of Eagle Ford Shale and Permian Basin assets;

offset by:

- record production volumes of 130 MMBoe;
- downward revisions of 307 MMBoe that were commodity price driven; and
- reduction of 6 MMBoe as a result of asset sales.

Price Revisions Of the 307 MMBoe price revisions, 116 MMBoe relate to proved developed reserves and 191 MMBoe relate to proved undeveloped reserves. Unlike proved undeveloped reserves, which require capital investment associated with drilling and development activities, proved developed reserves that were subject to downward price revisions, would not require additional capital investment to access the reserves if the commodity price increases.

Our proved reserves are 62% US and 38% international, and the mix is 35% global liquids (crude oil and NGLs), 33% international natural gas and 32% US natural gas.

See Proved Reserves Disclosures, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for further discussion of proved reserves.

Crude Oil and Natural 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 numerous areas of interest. These activities include geophysical and geological evaluation, analysis of commercial, regulatory and political risk and exploratory drilling, where appropriate. Our properties consist primarily of interests in developed and undeveloped crude oil and natural gas leases and concessions. We also own natural gas processing plants and natural gas gathering systems and other crude oil and natural gas-related pipeline systems. These assets are primarily used in the processing and transportation of our crude oil, natural gas and NGL production.

Exploration Activities We primarily focus on organic growth from exploration and development drilling, concentrating on basins or plays where we have strategic competitive advantages, emanating 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 exploration success in the deepwater Gulf of Mexico, the Douala Basin offshore West Africa and the Levant Basin offshore Eastern Mediterranean, resulting in a portfolio of major development projects. We have exploration opportunities remaining in these areas and have also engaged in new venture activity.

Although our focus on exploration activities has historically created a sustainable exploration program, we significantly reduced our 2015 exploration budget due to the current commodity price environment. Our 2016 exploration budget is also reduced but provides flexibility to respond to commodity price changes.

In 2015, we conducted exploration activities in domestic and international locations including the deepwater Gulf of Mexico, offshore West Africa and offshore the Falkland Islands.

Appraisal, Development and Production Activities Our discoveries and strategic acquisitions in recent years have provided us with numerous appraisal, development and production opportunities, as demonstrated in our inventory of major development projects. Although our capital budget for these activities was reduced in 2015, we continued to make significant progress on our ongoing onshore US and other major development projects.

Acquisition and Divestiture Activities We maintain an ongoing portfolio management program. Accordingly, we may 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 owning the assets. We may also periodically divest non-core, non-strategic assets.

Rosetta Merger On July 20, 2015, we completed the merger of Rosetta Resources Inc. (Rosetta) into a subsidiary of Noble Energy (Rosetta Merger). This merger adds two premier onshore US shale positions to our core operating areas: the Eagle Ford Shale and Permian Basin. Rosetta's liquids-rich asset base included approximately 50,000 net acres in the Eagle Ford Shale and 54,000 net acres in the Permian Basin (45,000 net acres in the Delaware Basin and 9,000 net acres in the Midland Basin). We are continuing to improve drilling and well performance in these unconventional plays by applying best practices from our onshore business and by capitalizing on Noble Energy - Rosetta synergies. See Item 8. Financial Statements and Supplementary Data - Note 3. Mergers, Acquisitions and Divestitures.

Suriname Entry In October 2015, we acquired a non-operated 20% working interest in Block 54 offshore Suriname via farm-in from Tullow Oil plc. Tullow is the operator with a 30% interest. The initial phase of exploration on the block requires acquisition of a 3D seismic survey, which has been completed and is currently being processed. Evaluation of the seismic survey will determine if a commitment to a subsequent exploration phase to drill an exploration well is warranted.

Offshore Israel Assets In November 2015, we signed an agreement to divest our 47% working interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields, to the Delek Group. The terms of the agreement simplify the ultimate sale to a third party by providing our partners with the exclusive right to conclude the full divestment of these assets. This agreement is an important step in fulfilling Noble Energy's obligations under the Natural Gas Framework. The transaction closed in January 2016 for a total transaction value of $73 million ($67 million for asset consideration and $6 million from adjustment of costs). These fields were not included in our proved reserves estimates at December 31, 2015. See Update on Israel – *Israel Natural Gas Framework* below.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with BG Group plc (BG) for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery. In January 2016, we received proceeds of $125 million related to the farm-out agreement and expect to receive the remaining consideration of $40 million, subject to post-close adjustments, in 2017. We remain operator of Block 12 with a 35% interest.

Non-Core Divestiture Program During 2015, we continued our non-core asset divestiture program with the sale of certain smaller onshore US property packages resulting in net proceeds of $151 million. Divestitures of non-core properties allow us to allocate capital and other resources to areas with potential for higher value and growth. We continue to evaluate divestment opportunities of certain non-core, onshore properties located in the Rocky Mountain and Bowdoin (north central Montana) areas.

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 3. Mergers, Acquisitions and Divestitures.

Asset Impairments We recorded $533 million in impairment charges for 2015, including $490 million in fourth quarter 2015. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Goodwill Impairment During fourth quarter 2015, we determined that our goodwill, which had arisen from previous mergers and been assigned to the US reporting unit, had been fully impaired and recorded impairment charges of $779 million. See Item 8. Financial Statements and Supplementary Data – Note 4. Goodwill.

United States

We have been engaged in crude oil, natural gas and NGL exploration and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 68% of 2015 total consolidated sales volumes and 62% of total proved reserves at December 31, 2015. Approximately 51% of the proved reserves in the US are natural gas, 29% are crude oil and condensate and 20% are NGLs.

Sales of production and estimates of proved reserves for our US operating areas were as follows:

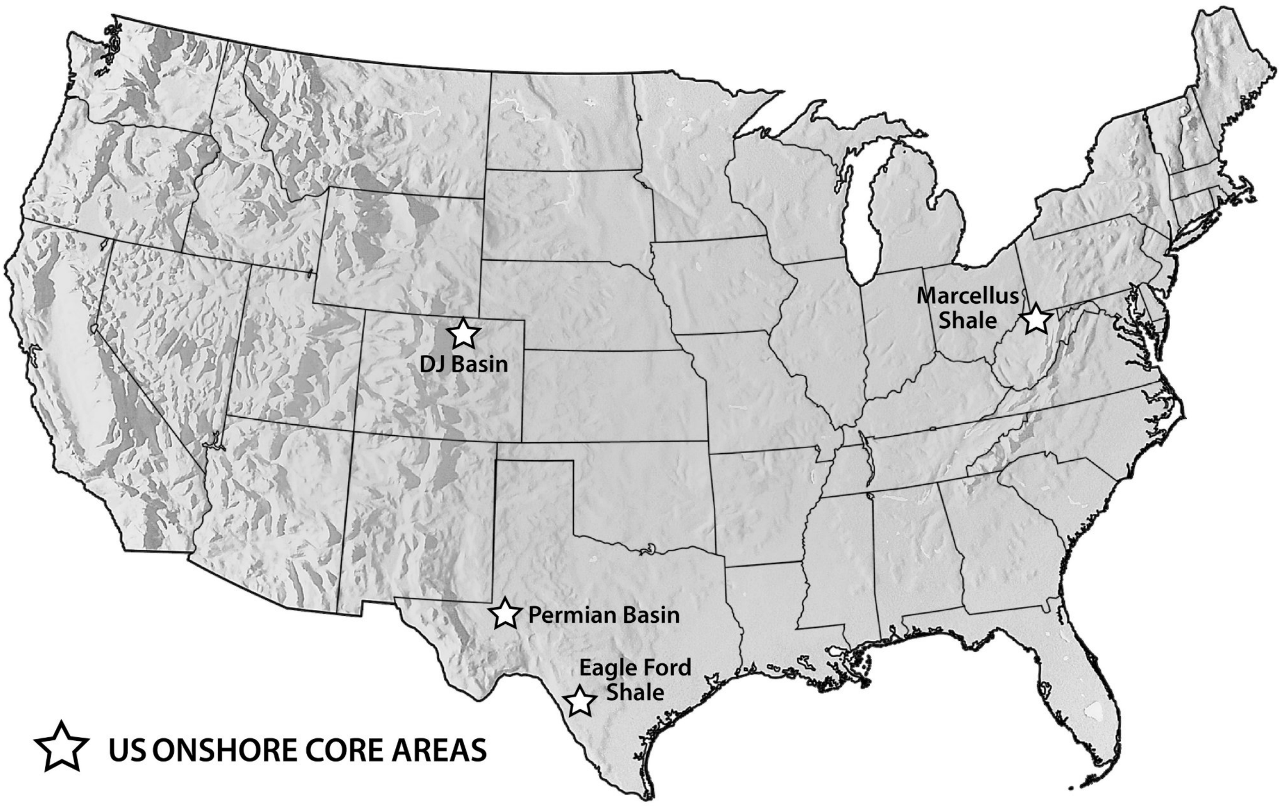
	Year Ended December 31, 2015				December 31, 2015			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
DJ Basin	57	234	19	115	160	861	70	374
Marcellus Shale	2	393	10	77	2	1,253	20	231
Eagle Ford Shale	5	55	8	22	36	485	77	194
Deepwater Gulf of Mexico	13	11	1	15	28	38	2	36
Other Onshore US	4	15	1	8	30	74	7	49
Total	81	708	39	237	256	2,711	176	884

Wells drilled in 2015 and productive wells at December 31, 2015 for our US operating areas were as follows:

	Year Ended December 31, 2015	December 31, 2015
	Gross Wells Drilled or Participated in [(1)]	Gross Productive Wells
DJ Basin	211	7,613
Marcellus Shale	89	509
Eagle Ford Shale	8	339
Permian Basin	13	205
Deepwater Gulf of Mexico	3	13
Other Onshore US	4	955
Total	328	9,634

(1) Excludes exploratory wells drilled and suspended awaiting a sanctioned development plan or being assessed for economic viability. See Drilling Activity, below.

Our onshore US operations are located in proven basins with long-life production profiles. These assets include low production-risk drilling opportunities that offer predictable and long-term production, and a balanced commodity mix of crude oil, natural gas and NGLs. Locations of our onshore US operations as of December 31, 2015 are shown on the map below:



DJ Basin With the advent of horizontal drilling technology, the DJ Basin is recognized as a premier US crude oil resource play and is a key driver of our business. Our position in the core area covers approximately 396,000 net acres.

In 2015 and currently, we are focusing our drilling and development activity on Integrated Development Plan (IDP) areas, such as Wells Ranch and East Pony, allowing us to consolidate processing and handling infrastructure across large areas (typically 30,000 to 80,000 acres). IDP's are areas of highly contiguous acreage where we can accelerate drilling and completion activities, drill a much higher percentage of extended reach lateral wells, and build our own centralized production facilities, gathering systems, and water infrastructure. With this approach, we construct multi-well horizontal drilling pads and centralized processing facilities (CPFs) to minimize surface use. The drilling pads and CPFs facilitate efficient execution of operations by reducing land surface and water usage while enabling us to efficiently gather and process crude oil, natural gas, NGLs and water from a large surrounding area, reducing truck traffic and our overall surface footprint. Additionally, our IDP approach has provided an opportunity to efficiently and economically support production growth by constructing and expanding our infrastructure across the DJ Basin.

2015 Activity In response to the current commodity price environment, we adopted a reduced and flexible 2015 capital program, responsive to changes in the commodity price environment. Due to continued low prices during 2015, we reduced our level of drilling activity in the basin. Operationally, we focused on reducing capital costs per unit and unit operating costs while increasing operating efficiencies to support project returns and margin improvements. Through material efficiency gains, midstream expansions and improved completion techniques, we were able to deliver higher production at lower capital and operating costs.

Despite a reduced drilling budget, we were able to expand our extended reach lateral well program to approximately 43% of wells drilled in 2015. During the year, we spud 171 horizontal wells, of which 72 were extended reach lateral wells, and 182 wells initiated production. We also participated in approximately 30 non-operated development wells during 2015.

In second quarter 2015, we began operation of the Keota plant, our second natural gas processing plant in northern Colorado, to support our East Pony IDP, providing additional capacity to support future development in this part of the basin.

The DJ Basin contributed an average of 115 MBoe/d of sales volumes in 2015, an increase of 14% over 2014 volumes, and representing approximately 33% of total consolidated sales volumes. DJ Basin sales volumes were approximately 50% crude oil and 17% NGLs.

Our 2015 DJ Basin development program resulted in net additions/revisions to proved reserves of approximately 71 MMBoe, approximately 74% of which are crude oil and NGLs. At December 31, 2015, proved reserves in the DJ Basin represented approximately 26% of our total proved reserves. See Proved Reserves Disclosures.

We exited 2015 with a three rig drilling program. However, commodity prices have continued to trade in a low range into 2016. We are engaged in a comprehensive effort to spend within cash flow and have again adopted a reduced and flexible capital spending program for 2016. The spending program provides flexibility to reassess activity levels in response to the commodity price environment that evolves during the remainder of 2016.

In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream oil and natural gas operations within the DJ Basin Non-Attainment Area. A Non-Attainment Area is any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for a pollutant. The Consent Decree was entered by the US District Court of Colorado on June 2, 2015. See Item 1.A. 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 18. Commitments and Contingencies.

Marcellus Shale The Marcellus Shale contains a significant quantity of natural gas resources, and its proximity to high-demand East Coast markets has made it a desirable area for development. Infrastructure improvements and expanding firm transportation capacity are expected to improve export of product to areas outside the basin, reduce basis differentials, and have a positive impact on project economics.

We have a 50-50 joint development agreement with CONSOL Energy, Inc. (CONSOL) in approximately 700,000 gross acres in southwest Pennsylvania and northwest West Virginia. We operate the wet gas (natural gas containing more liquid hydrocarbons) development area in Majorsville, West Virginia and Southwest Pennsylvania, and Moundsville, Shirley and Oxford, West Virginia, while CONSOL primarily operates in the dry gas (natural gas containing less liquid hydrocarbons) development area. Our joint development agreement with CONSOL provides for a multi-year drilling and development plan.

Utilizing an IDP concept, modeled after the DJ Basin, we have realized capital and operating cost efficiencies through multi-well pads, central facilities and efficient liquids infrastructure that enable us to minimize truck traffic, enhance completion design and optimize well placement. The current identified IDP areas are Majorsville, West Virginia, Southwest Pennsylvania Area Dry, and Allegheny County Airport, Pennsylvania. Majorsville, which came online in 2012 as the first operated IDP location, is in the core operating area with water and marketing infrastructure in place to support further development.

2015 Activity During 2015, the joint venture drilled a total of 89 wells. Noble drilled 41 of these wells with an average lateral length of 8,000 feet. The joint venture initiated production on 91 wells. During the year, we shifted our drilling activity away from the Marcellus Shale in response to low commodity prices, coupled with high basis differentials due to oversupply. However, operational performance remained strong, with volumes increasing 57% compared to 2014.

Currently, there are no operated or non-operated rigs running in the Marcellus Shale. For 2016, we and CONSOL have agreed to operate within cash flow and have agreed to a reduced development program for the year compared to the plan provided for under the multi-year drilling and development plan. This 2016 plan will focus on well completions and provides for fewer wells to be drilled than the number of wells that was provided for under the multi-year drilling and development plan, and a reduction of allocated capital to be invested in the Marcellus Shale core area. Our 2016 capital spending program provides flexibility to reassess activity levels in response to the commodity price environment, and other factors, that may evolve in this region during the remainder of the year.

The Marcellus Shale contributed an average of 462 MMcfe/d of sales volumes and represented approximately 22% of total consolidated sales volumes in 2015 and approximately 16% of total proved reserves at December 31, 2015. Our 2015 Marcellus Shale development program resulted in net additions/revisions to proved reserves of approximately 95 MMBoe, approximately 12% of which are crude oil and NGLs. See Proved Reserves Disclosures.

CONE Gathering We and CONSOL also operate CONE Gathering LLC (CONE Gathering), which constructs, owns and operates midstream infrastructure servicing our joint production, and is the general partner controlling interest in CONE Midstream Partners (CONE Midstream). CONE Midstream is a master limited partnership, formed in late 2014, in which we own a 32.1% interest accounted for using the equity method of accounting. During 2015, CONE Midstream continued to increase both revenues and average throughput as a result of new well connections and the impact of de-bottlenecking projects coming on line. Continued focus on cost optimization yielded decreases in operating expense as compared with the prior year.

Eagle Ford Shale and Permian Basin On July 20, 2015, we completed the Rosetta Merger, adding the Eagle Ford Shale and Permian Basin to our core areas (approximately 104,000 net acres total). During 2015, we drilled ten operated wells to total depth, including nine Lower Eagle Ford wells and one Wolfcamp A well in the Permian Basin, with reduced drilling times versus prior performance. We commenced production on eight operated Lower Eagle Ford wells and have applied IDP learnings from other US onshore assets to realize cost efficiencies, enhance completion design and optimize well placement.

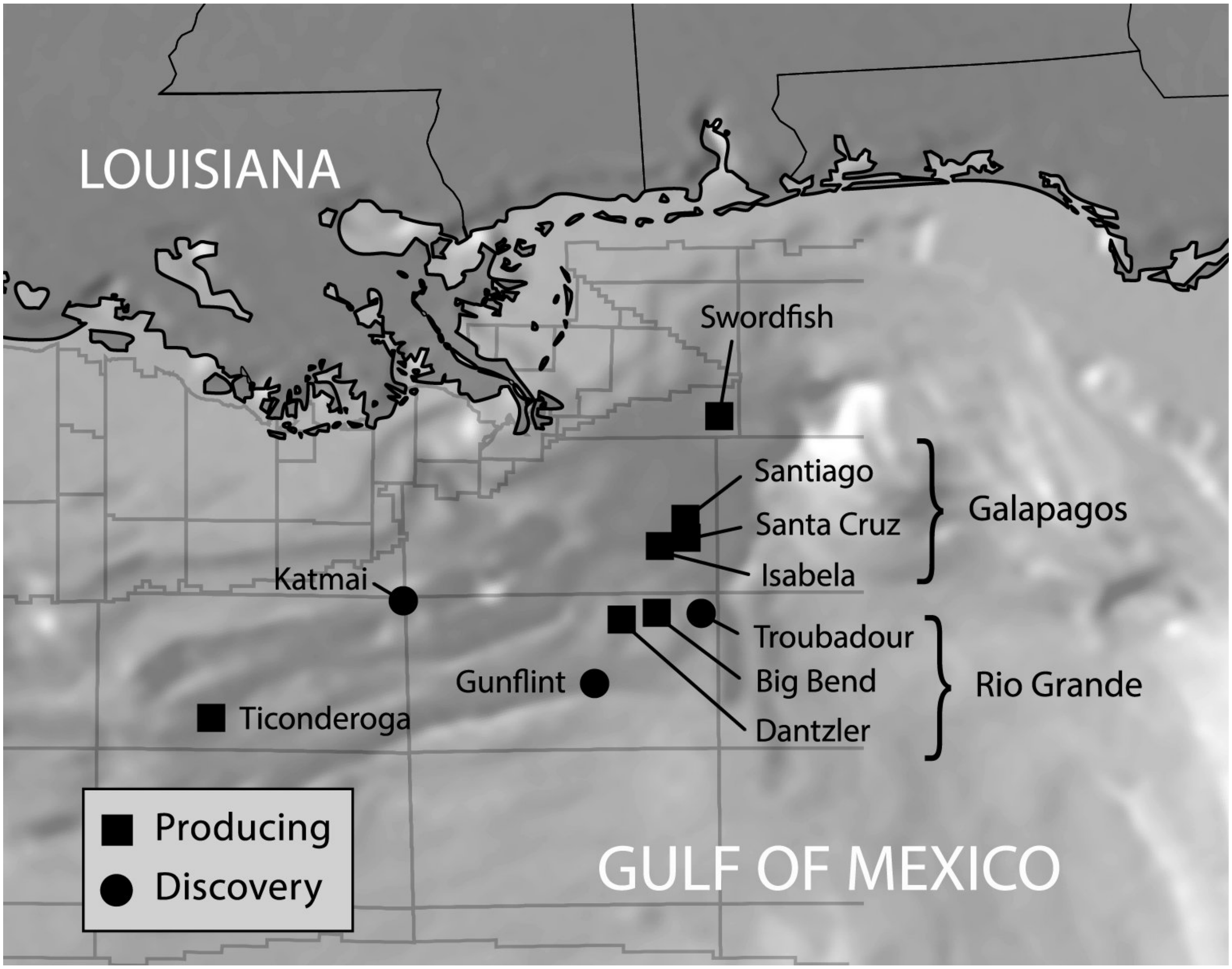
In 2015 and on a full year basis, these assets contributed an average of 26 MBoe/d of sales volumes, representing approximately 7% of total consolidated sales volumes, and were approximately 28% crude oil and 35% NGLs. These assets represented approximately 16% of total proved reserves at December 31, 2015.

We exited 2015 with two rigs operating, one in the Eagle Ford Shale and one in the Permian Basin. At the end of 2015, 55 wells were drilled but not complete. Commodity prices have continued to trade in a low range into 2016 and our 2016 capital spending program provides flexibility to reassess activity levels in response to the commodity price environment that evolves during the remainder of the year.

Other Non-Core Onshore Properties We also operate in the following onshore US areas: Rocky Mountains and Bowdoin (north central Montana). Other non-core onshore properties accounted for 1% of total consolidated sales volumes in 2015 and approximately 1% of total proved reserves at December 31, 2015. During 2015, we sold various non-core onshore properties and continue to evaluate divestment opportunities. See Acquisition and Divestiture Activities – *Non-Core Divestiture Program* above.

Northeast Nevada After assessing its commercial viability in the current commodity price environment, we elected to discontinue our exploration effort in northeast Nevada. During fourth quarter 2015, we recorded exploration expense of $95 million in conjunction with this exit.

Deepwater Gulf of Mexico Locations of our operations in the deepwater Gulf of Mexico as of December 31, 2015 are shown on the map below:



Noble Energy was one of the first independent producers to explore in the Gulf of Mexico. We acquired our first offshore block in 1968, and our focus has been on high-impact opportunities with the potential to provide sustained production and cash flow.

We have several producing fields, ongoing development projects and a substantial inventory of exploration opportunities.

In 2015, we completed Big Bend and Dantzler (Rio Grande project) ahead of schedule representing approximately three and two years development time from discovery to production, respectively. Production commenced fourth quarter with a combined peak rate of 20 MBoe/d, net.

We currently hold leases on 104 deepwater Gulf of Mexico blocks, representing approximately 39,000 net developed acres and approximately 329,000 net undeveloped acres. We are the operator on approximately 70% of our leases. See also Developed and Undeveloped Acreage – *Future Acreage Expirations*, below.

The deepwater Gulf of Mexico accounted for 4% of total consolidated sales volumes in 2015 and 3% of total proved reserves at December 31, 2015.

Deepwater Gulf of Mexico Exploration Program Our deepwater Gulf of Mexico operations resulted from lease acquisition, expansion of our 3D seismic database, and an active drilling program. We currently have an inventory of identified prospects, which are a combination of both high impact subsalt prospects and smaller tie-back opportunities. These prospects are subject to an ongoing technical maturation process and may or may not emerge as drillable options.

Our 2015 exploration budget was substantially reduced due to the current commodity price environment and effort to keep spending within our cash flows. However, we continued to engage in various exploration activities including spudding the Silvergate exploratory well, described below.

Our 2016 exploration budget has also been substantially reduced, but provides flexibility to respond to commodity price changes. We currently have capitalized undeveloped leasehold cost of approximately $247 million related to deepwater Gulf of Mexico prospects that have not yet been drilled. These leases will expire over the years 2016 - 2024 and some leases may become impaired if production is not established or should we not take action to extend the terms of the leases. As a result of our exploration activities, future leasehold expense could be significant.

In addition, new regulations are being considered by various federal agencies overseeing certain of our activities in the Gulf of Mexico. The Bureau of Safety and Environmental Enforcement recently issued a proposed rule intended to update standards for blowout prevention systems and other well controls for offshore oil and gas activities conducted in US federal waters, including the Gulf of Mexico, while the Bureau of Ocean Energy Management is in the process of updating its regulations and program oversight to establish more robust risk management, financial assurance and loss prevention requirements for oil and gas operations in the Outer Continental Shelf, including the Gulf of Mexico. These regulations, if ultimately adopted could, among other things, significantly increase the costs associated with our activities in the Gulf of Mexico and result in some of our undrilled leaseholds becoming uneconomic to drill.

See Regulations - *US Offshore Regulatory Developments*, Item 1A. Risk Factors, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Oil and Gas Exploration Expense.

2015 Activity We have a multi-year contract for the Atwood Advantage drillship. We used the drillship in our 2015 drilling plan which included various exploration, development and well completion activities. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Obligations.

Silvergate (Mississippi Canyon Block 339; 50% operated working interest) During fourth quarter 2015, we spud an exploratory well at the Silvergate prospect. The well is targeting the Middle Miocene objective with results expected in first quarter 2016.

Katmai (Green Canyon Block 40; 50% operated working interest) During 2014, we announced successful final well results at the Katmai exploratory well. Katmai was drilled to a total depth of 27,900 feet in 2,100 feet of water. Wireline logging data indicated a total of 154 net feet of crude oil pay discovered in multiple reservoirs, including 117 net feet in Middle Miocene and 37 net feet in Lower Miocene reservoirs. We plan to conduct additional appraisal drilling activities in 2016 to test the remaining resource potential and further define potential development scenarios.

Ongoing Major Development Projects

Gunflint (Mississippi Canyon Block 948; 31% operated working interest) Gunflint is a 2008 crude oil discovery, utilizing a two-well subsea tieback to the Gulfstar 1 spar platform. We are in the process of completing topsides modifications and facilities upgrades. Development is on track, and we are targeting first production for mid-2016.

Offshore Producing Properties

Galapagos Development Project including Isabela (Mississippi Canyon Block 562; 33.33% non-operated working interest), Santa Cruz (Mississippi Canyon Blocks 519/563; 23.25% operated working interest) and Santiago (Mississippi Canyon Block 519; 23.25% operated working interest) The Galapagos crude oil development project consists of Isabela, a 2007 discovery, Santa Cruz, a 2009 discovery, and Santiago, a 2011 discovery. The Galapagos development began producing in 2012 and is connected to existing infrastructure through subsea tiebacks. We expect to conduct workover activities at Isabela during 2016.

Rio Grande Development including Big Bend (Mississippi Canyon Block 698; 54% operated working interest) and Dantzler (Mississippi Canyon Block 782; 45% operated working interest) The Rio Grande crude oil development project consists of a single producing well from Big Bend, a 2012 crude oil discovery, and two producing wells from Dantzler, a 2013 crude oil discovery, flowing to the third-party Thunder Hawk platform. The Rio Grande development commenced production in October 2015 and contributed almost 3 MBoe/d of sales volumes in 2015 and currently produces approximately 20 MBoe/d.

Swordfish (Viosca Knoll Blocks 917; 961 and 962; 85% operated working interest) Swordfish is a 2001 crude oil discovery and began producing in 2005. The Swordfish project currently includes two producing wells flowing to the Neptune Spar, our floating offshore production platform.

Ticonderoga (Green Canyon Block 768; 50% non-operated working interest) Ticonderoga is a 2004 crude oil discovery and began producing in 2006. The project currently includes two producing wells. These properties are connected to existing infrastructure through subsea tiebacks.

Asset Impairments During 2015 and 2014, we recorded impairment expense of $158 million and $350 million, respectively, related to deepwater Gulf of Mexico properties. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

International

Our international business focuses on offshore opportunities in a number of countries and diversifies our portfolio. Development projects in Equatorial Guinea and Israel contributed substantially to our growth over the last decade.

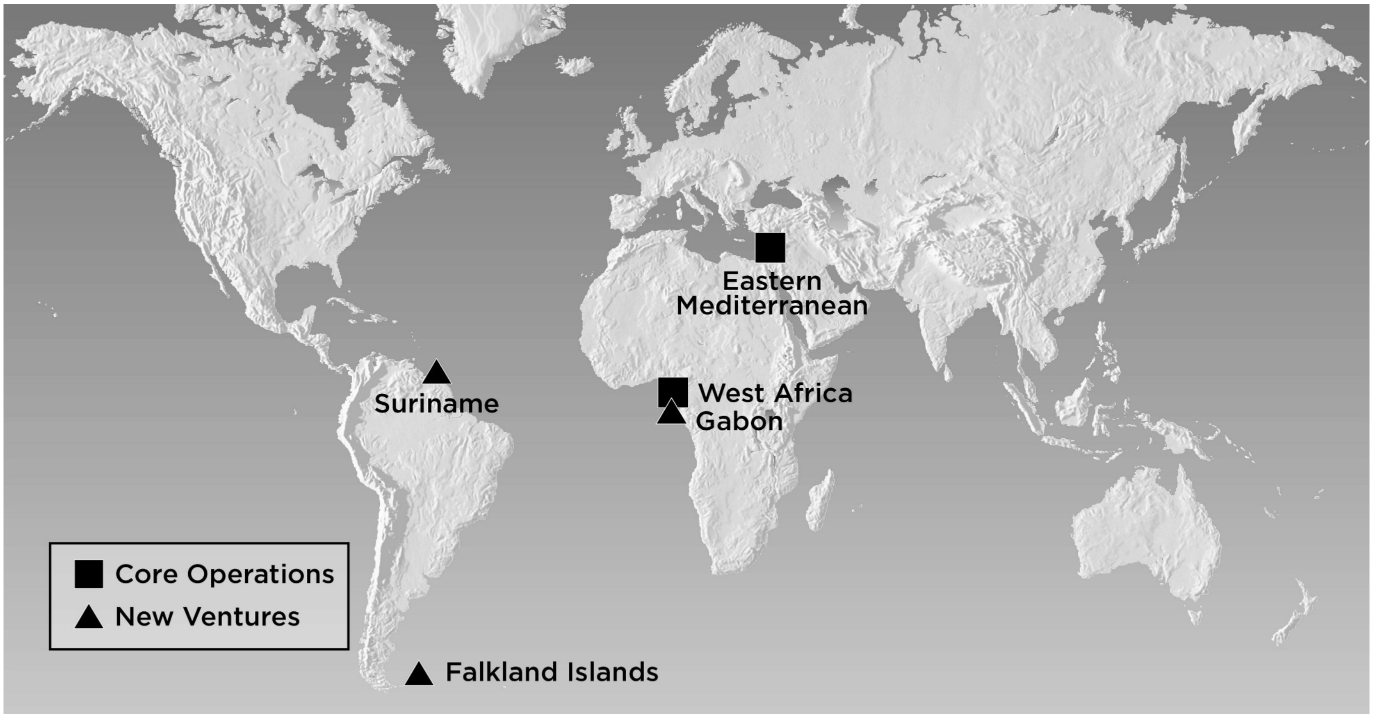
Previous exploration successes offshore West Africa, Israel and Cyprus have identified multiple major development projects that have the potential to contribute to production growth in the future. We drilled two exploratory wells in 2015, and our large acreage positions in West Africa and the Eastern Mediterranean could provide further exploration opportunities.

On the development side, during 2015, we completed the Tamar field compression project and advanced Eastern Mediterranean regional natural gas export opportunities. Our partners in the Alba field, offshore Equatorial Guinea, advanced the Alba field compression project.

International operations accounted for 32% of total consolidated sales volumes in 2015 and 38% of total proved reserves at December 31, 2015. International proved reserves are approximately 88% natural gas and 12% crude oil, NGLs and condensate.

Operations in Cyprus, Equatorial Guinea, Gabon and Suriname are conducted in accordance with the terms of Production Sharing Contracts (PSCs). In Cameroon, we operate in accordance with the terms of a PSC and a mining concession. Operations in Israel, the Falkland Islands, and other foreign locations are conducted in accordance with concession agreements, permits or licenses. See Item 1A. Risk Factors.

Locations of our international operations as of December 31, 2015 are shown on the map below:



Sales volumes and estimates of proved reserves for our international operating areas were as follows:

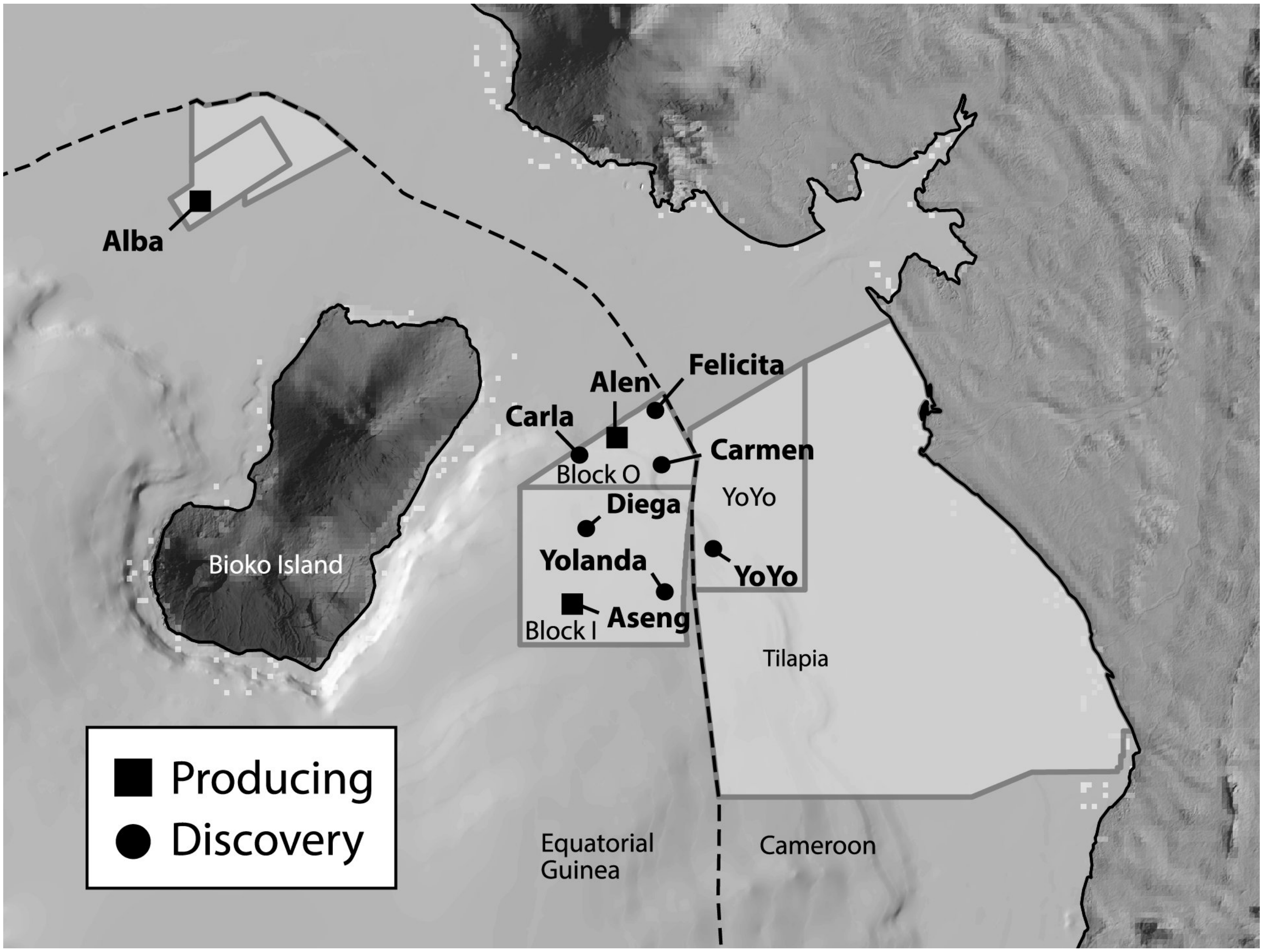
	Year Ended December 31, 2015				December 31, 2015			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
International								
Equatorial Guinea	31	227	—	69	48	534	13	151
Israel	—	252	—	42	3	2,304	—	386
Total International	31	479	—	111	51	2,838	13	537
Equity Investee	2	—	5	7	—	—	—	—
Total	33	479	5	118	51	2,838	13	537
Equity Investee Share of Methanol Sales (MMgal)				117				

Wells drilled in 2015 and productive wells at December 31, 2015 in our international operating areas were as follows:

	Year Ended December 31, 2015	December 31, 2015
	Gross Wells Drilled or Participated in	Gross Productive Wells
International		
Equatorial Guinea	1	26
Cameroon	1	—
Israel	—	8
North Sea	—	1
Falkland Islands	1	—
Total International	3	35

West Africa (Equatorial Guinea, Cameroon and Gabon) West Africa is one of our core operating areas and includes the Alba field, Block O and Block I offshore Equatorial Guinea, the YoYo mining concession and Tilapia PSC, offshore Cameroon, and one block offshore Gabon. Equatorial Guinea, the only producing country in our West Africa segment, accounted for approximately 20% of 2015 total consolidated sales volumes and 11% of total proved reserves at December 31, 2015. We held approximately 118,000 net developed acres and 30,000 net undeveloped acres in Equatorial Guinea, 511,000 net undeveloped acres in Cameroon, and 403,000 net undeveloped acres in Gabon at December 31, 2015. During second quarter 2015, we exited our position in Sierra Leone following processing of 2D seismic data.

Locations of our operations in Equatorial Guinea and Cameroon, as of December 31, 2015 are shown on the map below:



Aseng Field Aseng is a crude oil field on Block I (40% operated working interest), offshore Equatorial Guinea, which began producing in 2011. The development includes five horizontal wells flowing to the Aseng 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. Aseng produced approximately 11 MBoe/d, net, during 2015.

The Aseng FPSO is designed to act as a crude oil production hub, as well as 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 and safe performance, averaging almost 99% production uptime.

Alen Field Alen is a natural gas and condensate field primarily on Block O (45% operated working interest), offshore Equatorial Guinea, which includes three production wells and three natural gas injection wells connected to a production platform that utilizes the Aseng FPSO for storage and offloading. Alen has been producing since 2013 and produced approximately 13 MBoe/d, net, during 2015.

Alba Field We have a 34% non-operated working interest in the Alba field, offshore Equatorial Guinea, which has been producing since 1991. Operations include the Alba field and related production and condensate storage facilities, an 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. The LPG processing plant and the methanol plant are located on Bioko Island, Equatorial Guinea. The Alba field produced approximately 45 MBoe/d, net, during 2015.

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 and an unaffiliated LNG plant. The

LPG plant is owned by Alba Plant LLC (Alba Plant), in which we have a 28% interest accounted for as an equity method investment. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest, also accounted for as an equity method investment. 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. Both the AMPCO methanol plant and the ALBA LPG plant are scheduled for turnaround activities during first quarter 2016.

During 2015, we participated in the drilling of one development well. The Alba compression project installation progressed and is expected to be completed in early second quarter 2016.

Other Block O & I Projects We are currently processing the results of recently acquired 3D seismic data across Equatorial Guinea Blocks O and I which will aid in advancing other regional exploration and development opportunities, including the Diega/Carmen and Carla discoveries.

Asset Impairments During 2015, we recorded impairment expense of $339 million related to offshore Equatorial Guinea properties due to a decline in future crude oil prices. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Cameroon We have an interest in over one million gross undeveloped acres offshore Cameroon, which include the YoYo mining concession (50% operating working interest) and Tilapia PSC (46.67% operating working interest). Petronas holds the other 50% operating working interest in the YoYo mining concession and has given notice to us and the Cameroon government of their intention to exit the YoYo mining concession. Once the assignment process is finalized, we will hold 100% operating working interest in the YoYo mining concession. We have begun efforts to market this additional working interest.

The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options and are negotiating with the Cameroon government to convert the YoYo mining concession to a PSC. We have completed reprocessing of 3D seismic data over our YoYo mining concession and are currently evaluating the data.

In 2015, we drilled the Cheetah exploration prospect on the Tilapia license (46.67% working interest), offshore Cameroon. The well encountered both crude oil and natural gas shows in multiple non-commercial reservoir sands and was plugged and abandoned. In 2015, we recorded dry hole costs of $33 million associated with this exploratory well. Results from the well are being integrated into our geologic modeling for the remaining exploration potential in the Tilapia license.

West Africa Natural Gas Project The West Africa natural gas project includes the 2007 Yolanda discovery (Block I) and 2008 Felicita discovery (Block O), offshore Equatorial Guinea, the YoYo discovery, offshore Cameroon, and associated natural gas from Aseng and Alen, offshore Equatorial Guinea. A natural gas development team is working with each government to evaluate natural gas monetization options. In addition, we are working to finalize a data exchange agreement between the two countries as a first step towards unitization of any cross border resources.

Offshore Gabon We are the operator of Block F15 (60% working interest), an undeveloped, ultra-deep water area, covering approximately 671,000 gross acres. The exploration phase is underway and we are planning to conduct a 3D seismic survey in the first half of 2016.

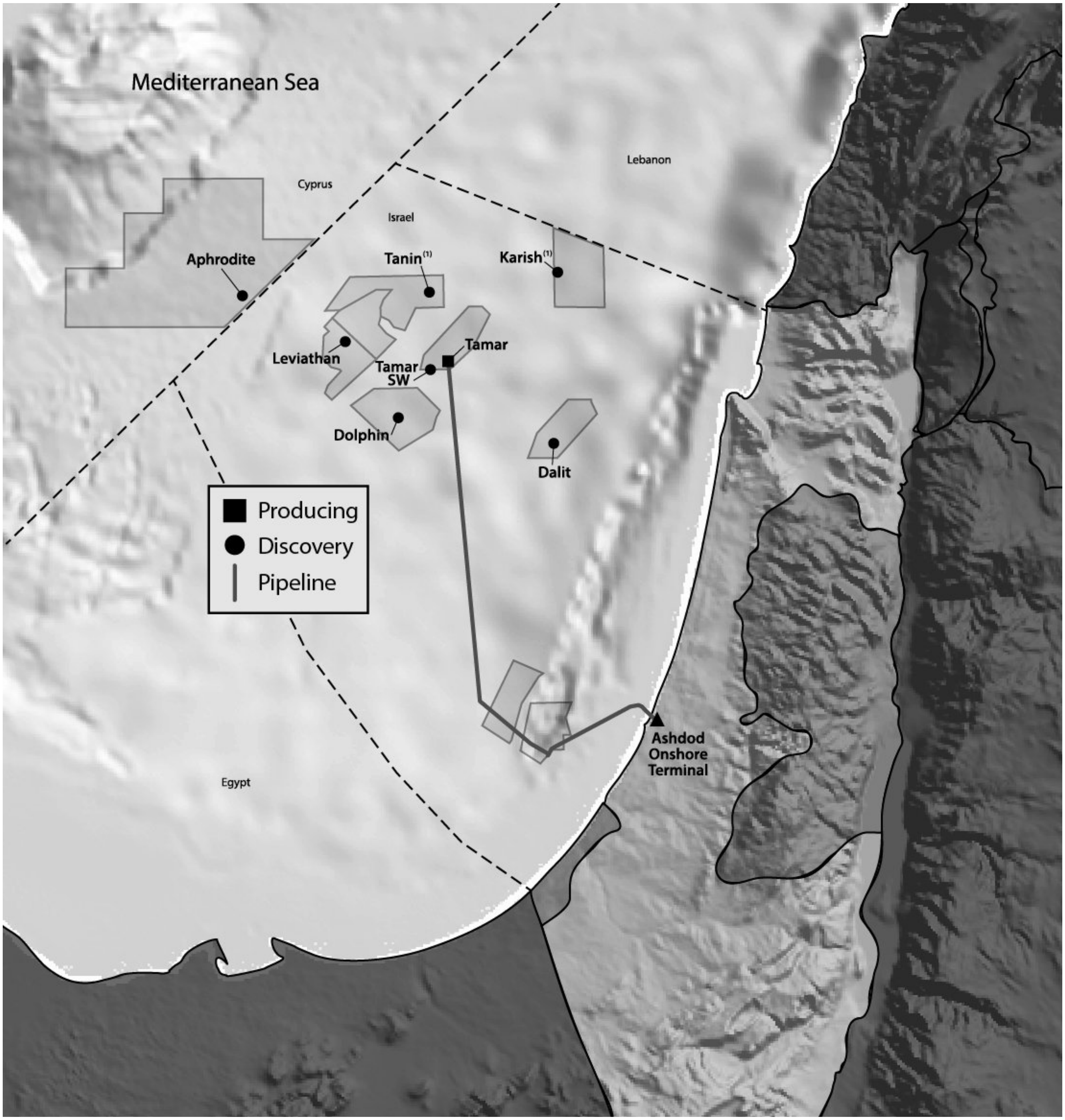
See also Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

Eastern Mediterranean (Israel and Cyprus) One of our core operating areas is the Eastern Mediterranean, where we have drilled 11 successful exploration and appraisal wells and identified the existence of substantial natural gas resources since we obtained our first exploration license offshore Israel in 1998.

Israel, our only producing country in our Eastern Mediterranean core area, accounted for 12% of 2015 total consolidated sales volumes and 27% of total proved reserves at December 31, 2015. Our leasehold position in the Eastern Mediterranean at December 31, 2015, included eight leases and three licenses operated offshore Israel and one license operated offshore Cyprus. Eastern Mediterranean acreage includes the Alon A and Alon C licenses which were converted to the Karish and Tanin leases in 2015 and subsequently divested in January 2016.

At December 31, 2015, the Eastern Mediterranean position included approximately 80,000 net developed acres and 261,000 net undeveloped acres located between 10 and 90 miles offshore Israel in water depths ranging from 700 feet to 6,500 feet. The license offshore Cyprus covers approximately 464,000 net undeveloped acres adjacent to our Israel acreage.

Locations of our operations in the Eastern Mediterranean as of December 31, 2015 are shown below:



(1) In January 2016, we closed the sale of our Karish and Tanin natural gas discoveries.

Update on Israel Noble Energy and our partners have remained committed to providing natural gas to Israeli citizens for over a decade. During this time we have reliably and consistently delivered approximately 1.6 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 natural gas 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 historical industry standards for an offshore natural gas project of this magnitude and complexity.

We continue to partner with customers and the Government of Israel to provide a reliable fuel source to support affordable energy for the people of Israel. 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 become a significant natural gas exporter. Multiple markets exist in the region, and Israel's domestic demand is predicted to continue to grow over the next decade.

In addition to our natural gas discoveries, the Levant Basin has potential for large scale crude oil discoveries, which may exist at greater depths. We have conducted preliminary exploration activities and are working on potential well design and placement to assess the presence of crude oil in the basin.

Israel Natural Gas Framework We have been progressing plans to develop the Leviathan field and expand the currently producing Tamar field. Historically we have had to address certain fiscal, antitrust and other regulatory challenges in Israel. These challenges have been addressed with the enactment of a comprehensive regulatory natural gas framework (Natural Gas Framework) by the Government of Israel. The Natural Gas Framework provides clarity on numerous matters concerning resource development which we will rely upon to support a final investment decision and upon which we can develop our resources while ensuring economic benefits to the state of Israel and its citizens. Among other items, the Natural Gas Framework provides for the following:

- the timely approval of asset development permits and plans and export permits;
- benchmarking future domestic contract pricing for an interim period until market competition is established, whereby such contracts are indexed to existing domestic and export contracts;
- resolution of antitrust and competition concerns, whereby we would divest Karish and Tanin within 14 months and reduce our ownership in Tamar to 25% within six years;
- the de-linking of Tamar export timing from Leviathan, enabling Tamar expansion to move forward; and
- support for investment and industry growth through stabilization assurance.

The Natural Gas Framework also enables marketing of Leviathan natural gas to Israeli customers for the first time. The development of Leviathan will substantially expand Noble Energy's capacity to deliver natural gas to Israel and the region, as well as provide a second source of domestic natural gas supply and redundancy of infrastructure for the people of Israel. The implementation of the Natural Gas Framework is a significant milestone towards the completion of the natural gas sales agreements with purchasers in Jordan and Egypt and obtaining financing for the project. With the strong support for the Natural Gas Framework demonstrated by the Government of Israel, the quantity and quality of discovered natural gas resources, regional demand for natural gas and the significant associated economic benefit to the government, citizens of Israel and the region, we plan to move forward with completing natural gas sales agreements, securing project financing and finalizing development scenarios to prepare the Tamar expansion and Leviathan development projects for final investment decisions.

The Israel Supreme Court held two hearings in February 2016 to consider legal challenges to the Natural Gas Framework, including the Government of Israel's enactment of Section 52 of the Restrictive Trade Practices Act and constitutional aspects of the stability undertakings. The Court requested a response whether the government will be willing to consider enacting legislation that will support the stability provisions of the Framework. We cannot predict what will be the response from the Government of Israel nor determine the outcome of these hearings.

In November 2015, we executed an agreement to divest our 47% interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields, to the Delek Group. The terms of the agreement simplify the ultimate sale to a third party by providing our partners with the exclusive right to conclude the full divestment of these assets. This agreement is an important step in fulfilling Noble Energy's obligations under the Natural Gas Framework. The transaction closed in January 2016 for a total transaction value of $73 million ($67 million for asset consideration and $6 million from adjustment of costs).

As of December 31, 2015, our $2.1 billion investment in Israel includes: approximately $1.4 billion related to the currently-producing Tamar field; approximately $400 million related to the Leviathan natural gas discovery and suspended deep oil test; approximately $200 million related to the Tamar expansion project and previous discoveries which are awaiting sanction of development plans; and $67 million related to the Karish and Tanin discoveries, which were included in assets held for sale.

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, is also increasing. These sectors are gaining confidence that a long-term supply of natural gas will be available and are now investing the capital necessary to convert facilities to use natural gas. We expect that government requirements for emissions reductions could also drive incremental demand for natural gas in the future. We have executed numerous natural gas sales and purchase agreements (GSPAs) with domestic customers. See International Marketing Activities and Delivery Commitments, below.

Regional Demand and Exports The Eastern Mediterranean presents an opportunity to match our low cost, abundant supply of natural gas with large regional demand. With the Tamar field already on line, and the Leviathan field appraised and flow tested, we are well positioned to supply natural gas to the region for many years.

With the clarity provided by implementation of the Natural Gas Framework, we are continuing to negotiate contracts for natural gas sales to supply LNG plants in Egypt and the National Electric Power Company in Jordan through a regional pipeline system. We have natural gas sales and purchase agreements with Dolphinus Holdings for up to 250 MMbtu of interruptible natural gas sales to Egypt from current Tamar capacity. We also have a natural gas sales and purchase agreement in place for Tamar natural gas sales of 66 Bcf to the Jordan Bromine and Arab Potash companies in Jordan, with sales beginning at the end of 2016. In addition, we have signed a letter of intent with Dolphinus Holdings for up to 4 BCM (approximately, 140 Bcf) annually from Leviathan for the Egyptian market. See *Israel Natural Gas Framework* above and Item 1A. Risk Factors – *Our Eastern Mediterranean natural gas marketing activities bear certain geopolitical, regulatory, economic and financial risks that could adversely impact our ability to monetize our Israel and Cyprus natural gas assets.*

Tamar Natural Gas Projects (36% operated working interest) The Tamar project began production in March 2013 and has peak flow rates of approximately 1.1 Bcf/d, gross, to support seasonal high demand periods. Growth in power and industrial demand in Israel, coupled with almost 100% uptime, enabled us to set new records for sales from our Tamar field in August 2015 of more than 1.0 Bcf/d, gross. Net production from Tamar averaged 254 MMcfe/d for 2015.

During 2015, we completed the Tamar compression project, which expanded field production capacity by adding compression at the Ashdod onshore terminal (AOT).

Also during 2015, we continued to work with the Government of Israel to obtain regulatory approval of the development plan for our 2013 Tamar Southwest discovery (36% operated working interest), which is intended to utilize current Tamar infrastructure.

We have also engaged in the planning phase for the Tamar expansion project. The expansion development project would expand field deliverability to approximately 2.1 Bcf/d, a quantity that would allow for regional export. Expansion would include a third flow line component and additional producing wells.

Leviathan Natural Gas Project (39.66% operated working interest) Due to Leviathan's size, full field development is expected to require several development phases, with an overall development plan expected to serve both domestic demand and export markets.

In 2016, we will focus on finalizing GSPAs with multiple domestic and regional customers for the first phase of Leviathan. The GSPAs will be subject to, among other conditions, the receipt of regulatory approvals.

We are currently evaluating various development scenarios. Along with our original FPSO design, an additional concept utilizes a fixed platform to ensure timely first production. This fixed platform option provides greater flexibility to match initial contracted volumes, while retaining the ability to be expanded for additional contracts.

Timing of a final investment decision will depend on receipt of necessary regulatory approvals, the success of our marketing activities and securing of project financing.

Other Discoveries Offshore Israel We and our partners previously submitted a development plan for the Dalit field (36% operated working interest), a 2009 natural gas discovery. Development would include a tieback to the Tamar platform. We are using recent 3D seismic data to reevaluate the potential of the area, including the possible existence of hydrocarbons at deeper intervals.

We have submitted a commerciality package for Dolphin (39.66% operated working interest), including a potential tieback to Leviathan. We are also designing a drilling plan specifically for a potential test of a Mesozoic deep oil concept (Leviathan-1 Deep) and working on potential well design and placement.

Asset Impairments During 2015 and 2014, we recorded impairment expense of $36 million and $14 million, respectively, related to offshore Israel properties. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with BG for a portion of our interest in Block 12, which includes the Aphrodite natural gas discovery. The agreement was approved by the Government of Cyprus and completed in January 2016 whereby BG acquired a 35% interest in Block 12 for total cash consideration of $165 million, $125 million of which was received in January 2016 and the remainder of which will be paid in 2017. We will continue to operate with a 35% interest. Also, as part of the BG farm-out process, we negotiated a waiver of our remaining exploration well obligation.

During 2015, we submitted a Declaration of Commerciality and a Development Plan to the Government of Cyprus. We continue to work with the Government of Cyprus to obtain approval of the development plan and the issuance of an Exploitation License for the Aphrodite field. Receiving an Exploitation License, in conjunction with securing markets for Aphrodite gas, will allow us and our partners to perform the necessary front-end engineering design (FEED) studies and progress the project to final investment decision.

In preparation for FEED, we and our partners are currently performing preliminary engineering and design (pre-FEED) for the potential development of Aphrodite field that, as currently planned, would deliver natural gas to potential customers in Cyprus and Egypt.

See also Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

Other International

Our other international operations accounted for less than 1% of total consolidated sales volumes for 2015 and had no proved reserves at December 31, 2015.

Offshore Falkland Islands We drilled the Humpback exploration prospect (35% operated working interest), located in the South Falkland Basin in 2015. After evaluating results, we plugged and abandoned this exploratory well as we did not locate commercial quantities of hydrocarbons. As a result, we recorded dry hole costs of $140 million in 2015.

In 2015, we acquired the PL001 License in the North Falkland Basin, which covers an area of approximately 280,000 gross acres. We identified the Rhea prospect (75% operated working interest) as the initial target on the PL001 License. However, we experienced material operational issues with the drilling unit while drilling the Humpback well and the drilling contract was terminated on February 11, 2016. We remain confident in the potential of the Rhea prospect, which is located near the Sea Lion discovery in a proven petroleum system. We have been and will continue to work closely with our partners and the Falkland Islands Government to evaluate a path forward that includes retaining flexibility for the Rhea exploration well.

An Argentine court has initiated a criminal investigation against Noble Energy and other oil and gas companies regarding their exploration activities offshore Falkland Islands. The court has also issued a preservation order against the relevant companies to preserve assets in the event of any judgment. The investigation is premised on Argentina's claim that the Falkland Islands are a part of its territory. Argentina does not recognize the United Kingdom's sovereignty over the Falkland Islands or the Falkland Islanders rights to exploit their natural resources. The Falkland Islands are part of the United Kingdom's overseas territories and are afforded full self-governance. Our concessions are with the Falkland Islands Government and we do not believe that Argentina has any authority over our operations in the Falkland Islands.

Offshore Suriname In October 2015, we acquired a non-operated 20% working interest in Block 54 offshore Suriname in the Atlantic Ocean via farm-in from Tullow Oil plc. Tullow is the operator with a 30% interest. The initial phase of exploration on the block requires acquisition of a 3D seismic survey, which has been completed and is currently being processed. Evaluation of the seismic survey will determine if a commitment to a subsequent exploration phase to drill an exploration well is warranted.

North Sea The non-operated MacCulloch field is currently undergoing decommissioning activities.

Proved Reserves Disclosures

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 the Securities and Exchange Commission (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, newly sanctioned development projects, and certain fields selected on a rotational basis, 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.

In addition, our Company-wide short-term incentive plan does not include quantitative targets for proved reserves additions.

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 different geographical regions. These reserves estimates are reviewed and approved by regional 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, environmental analysis 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 35 years of industry experience 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, including the material additions to the 2015 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 2015, 2014, and 2013, we retained NSAI to perform audits of proved reserves. The reserves audit for 2015 included a detailed review of nine of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 85.1% of US proved reserves and 99.9% of international proved reserves (91% of total proved reserves). The reserves audit for 2014 included a detailed review of eight of our major fields and covered approximately 88% of total proved reserves. The reserves audit for 2013 included a detailed review of nine of our major fields and covered approximately 85% of total proved reserves.

In connection with the 2015 reserves audit, NSAI prepared its own estimates of our proved reserves. In order to prepare its estimates of proved reserves, NSAI examined our estimates with respect to reserves quantities, future production rates, future net revenue, and the present value of such future net revenue. NSAI also examined our estimates with respect to reserves categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI which brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

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, 2015, 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 is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

When compared on a field-by-field basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. For proved reserves at December 31, 2015, on a quantity basis, the NSAI field estimates ranged from 11 MMBoe or 5% above to 17 MMBoe or 6% below as compared with our estimates on a field-by-field basis. Differences between our estimates and those of NSAI are reviewed for accuracy but are not further analyzed unless the aggregate variance is greater than 10%. Reserves differences at December 31, 2015 were, in the aggregate, approximately 23 MMBoe, or 2%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2015, our PUDs totaled 133 MMBbls of crude oil and condensate, 1.6 Tcf of natural gas, and 83 MMBbls of NGLs for a total of 485 MMBoe. Changes in PUDs that occurred during the year are summarized below:

(MMBoe)	United States	Equatorial Guinea	Israel	Total
Proved Undeveloped Reserves Beginning of Year	390	59	74	523
Revisions of Previous Estimates	(177)	2	(3)	(178)
Extensions, Discoveries and Other Additions	77	—	—	77
Purchase of Minerals in Place	143	—	—	143
Sale of Minerals in Place	—	—	—	—
Conversion (to) from Proved Developed	(89)	9	—	(80)
Proved Undeveloped Reserves End of Year	344	70	71	485

Revisions of previous estimates include the transfer of PUDs to unproved reserve categories as a result of changes in development plans and/or the impact of changes in commodity prices, and the addition of new PUDs arising from current development plans. Negative revisions of 177 MMBoe in the US for 2015 included:

- the transfer to unproved reserves of 183 MMBoe due to negative price revisions attributed to low commodity price outlook and negative revisions of 48 MMBoe due to reduced future development activity, primarily in the DJ Basin;

offset by:

- 54 MMBoe positive revisions primarily in the Marcellus Shale, Eagle Ford Shale and Permian Basin due to current drilling and development plans.

Extensions, discoveries and other additions include addition of proved reserves through additional drilling or the discovery of new reservoirs in proven fields. During 2015, we recorded additions of 68 MMBoe and 9 MMBoe in the DJ Basin and Marcellus Shale, respectively, as a result of successful expansion of our extended reach lateral well programs.

Purchases of minerals included 119 MMBoe and 24 MMBoe in the Eagle Ford Shale and Permian Basin, respectively, as a result of the Rosetta Merger.

Conversion to proved developed reserves primarily included the transfer of 39 MMBoe, 22 MMBoe, 17 MMBoe and 11 MMBoe from the Marcellus Shale, DJ Basin, Eagle Ford Shale and deepwater Gulf of Mexico, respectively. In 2015, we converted 89 MMBoe of US PUDs, or 23% of our 2014 US PUD balance, to developed status. Based on our current inventory of identified horizontal well locations and our anticipated rate of drilling and completion activity, we expect our US PUDs as of December 31, 2015 to be converted to proved developed reserves well within a five-year period.

US PUDs Locations As of December 31, 2015, our US PUDs included:

- 147 MMBoe in the DJ Basin;
- 50 MMBoe in the Marcellus Shale;
- 102 MMBoe in the Eagle Ford Shale;
- 31 MMBoe in the Permian Basin; and
- 14 MMBoe in the deepwater Gulf of Mexico primarily associated with the Gunflint project.

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, 2015, we had approximately 98 MMBoe of proved undeveloped reserves associated with DUC well locations related to our onshore US operations, approximately one-half of which are in the Marcellus Shale, nearly one-third are in the Eagle Ford Shale and the remainder are in the DJ Basin and Permian Basin.

International PUDs Locations As of December 31, 2015, our international PUDs included:

- 70 MMBoe in the Alba field, offshore Equatorial Guinea, all of which have been recorded as PUDs for over five years and are attributable to a sanctioned compression project which is currently under construction and expected to come online mid-2016. These volumes, which will be recovered through existing wells, will be reclassified to proved developed at start-up, currently expected in second quarter 2016; and

- 71 MMBoe in Israel primarily in the Tamar and Tamar Southwest fields, including PUDs of 32 MMBoe related to the Tamar Southwest field, which is awaiting government approval of the development plan.

PUDs include no material amounts, except the Alba field PUDs of 70 MMBoe, which have remained undeveloped for five years or more since initial disclosure.

Development Costs Costs incurred to advance the development of PUDs were approximately $1.5 billion in 2015, $2.0 billion in 2014, and $1.0 billion in 2013. A significant portion of costs incurred in 2015 related to the DJ Basin, deepwater Gulf of Mexico and Marcellus Shale development projects.

Estimated future development costs relating to the development of PUDs are projected to be approximately $0.7 billion in 2016, $0.7 billion in 2017, and $0.8 billion in 2018. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. PUDs related to major development projects will be reclassified to proved developed reserves when production commences.

Drilling Plans All PUD drilling locations are scheduled to be drilled prior to the end of 2020. PUDs associated with the Alba field compression project are also expected to be converted to proved developed reserves prior to the end of 2016. Initial production from these PUDs is expected to begin during the years 2016 - 2020.

PUDs with Negative PV10 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 SEC pricing rules. Although our PUD reserves meet the SEC definition, this prescribed calculation can result in some PUDs having negative present worth, meaning while we have positive cash flows, the rate of return is lower than 10%.

At December 31, 2015, we had 195 PUD well locations, primarily located in the DJ Basin and Permian Basin, with a negative present worth when discounted at 10% and based on SEC prices. Net quantities totaled 28 MMBbl of crude oil and condensate, 173 Bcf of natural gas, and 9 MMBbl of NGLs. These amounts represented approximately 19% of total PUD locations and approximately 14% of total PUD quantities at December 31, 2015.

Although these PUD reserves had a negative present worth when discounted at 10%, they generated positive future net revenues.

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 these reserves within five years. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2016 Capital Investment Program.

For more information see the following:

- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Proved Reserves for a discussion of changes in proved reserves;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Reserves for further discussion of our reserves estimation process; and
- Item 8. Financial Statements and Supplementary Data – Supplementary Oil and Gas Information (Unaudited) for additional information regarding estimates of crude oil, natural gas and NGL reserves, including estimates of proved, proved developed, and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in the standardized measure of discounted future net cash flows.

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

	Sales Volumes			Average Sales Price			Production Cost [1]
	Crude Oil & Condensate MBbl	Natural Gas MMcf	NGLs MBbl	Crude Oil & Condensate Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per BOE
Year Ended December 31, 2015							
United States							
DJ Basin	20,909	85,369	6,910	$ 44.37	$ 2.53	$ 14.21	$ 5.51
Marcellus Shale	673	143,465	3,480	22.39	1.75	—	1.40
Eagle Ford Shale	1,656	19,969	3,074	31.65	2.25	13.44	3.15
Other US	6,024	9,837	631	45.91	3.18	12.34	8.90
Total US	29,262	258,640	14,095	43.46	2.10	10.39	4.28
Equatorial Guinea [2]	11,416	82,729	—	48.85	0.27	—	5.22
Israel							
Tamar Field	121	91,884	—	46.91	5.34	—	2.04
Other Israel	—	136	—	—	3.01	—	—
Total Israel	121	92,020	—	46.91	5.34	—	3.15
United Kingdom	88	49	—	55.52	6.32	—	41.07
Total Consolidated Operations	40,887	433,438	14,095	45.00	2.44	10.39	$ 4.43
Equity Investee [3]	554	—	1,850	48.85	—	28.40	
Total Continuing Operations	41,441	433,438	15,945	$ 45.05	$ 2.44	$ 12.48	
Year Ended December 31, 2014							
United States							
DJ Basin	18,209	75,039	6,072	$ 87.86	$ 4.11	$ 34.51	$ 6.00
Marcellus Shale	239	95,564	1,812	69.50	3.57	23.77	1.55
Other US	5,845	18,211	532	95.84	4.35	32.14	7.40
Total US	24,293	188,814	8,416	89.60	3.86	32.04	5.33
Equatorial Guinea [2]	12,191	88,833	—	94.61	0.27	—	5.44
Israel							
Tamar Field	109	79,828	—	89.62	5.68	—	2.81
Other Israel	—	4,539	—	—	3.52	—	22.11
Total Israel	109	84,367	—	89.62	5.57	—	3.84
China	788	—	—	103.74	—	—	8.53
United Kingdom	159	56	—	102.02	16.26	—	88.17
Total Consolidated Operations	37,540	362,070	8,416	91.58	3.38	32.04	$ 5.31
Equity Investee [3]	605	—	1,934	96.53	—	62.89	
Total Continuing Operations	38,145	362,070	10,350	$ 91.65	$ 3.38	$ 37.81	
Year Ended December 31, 2013							
United States							
DJ Basin	16,826	76,267	5,048	$ 93.28	$ 3.50	$ 36.33	$ 4.75
Marcellus Shale	45	50,645	351	79.62	3.67	30.92	2.54
Other US	6,133	33,796	635	105.56	3.44	31.73	12.08
Total US	23,004	160,708	6,034	96.53	3.54	35.53	6.03
Equatorial Guinea [2]	11,420	91,805	—	107.48	0.27	—	3.96
Israel							
Tamar Field	77	55,794	—	100.49	5.32	—	2.61
Other Israel	—	20,483	—	—	4.22	—	6.78
Total Israel	77	76,277	—	100.49	5.02	—	3.73
China	1,569	—	—	103.21	—	—	9.45
Total Consolidated Operations	36,070	328,790	6,034	100.29	2.97	35.53	$ 5.35
Equity Investee [3]	635	—	2,084	105.37	—	68.12	
Total Continuing Operations	36,705	328,790	8,118	$ 100.38	$ 2.97	$ 43.90	

(1) Average production cost includes crude oil and natural gas operating costs and workover and repair expense and excludes production and ad valorem taxes and transportation expenses.

(2) Natural gas from the Alba field is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(3) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea.

Revenues from sales of crude oil, natural gas and NGLs have accounted for 90% or more of consolidated revenues for each of the last three fiscal years.

At December 31, 2015, our operated properties accounted for the majority 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, 2015 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	5,580	5,222	4,054	2,816	9,634	8,038
Equatorial Guinea	5	2	21	8	26	10
Israel	—	—	8	3	8	3
United Kingdom	—	—	1	—	1	—
Total	5,585	5,224	4,084	2,827	9,669	8,051

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 gross wells is the total number of wells 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.

Developed and Undeveloped Acreage Developed and undeveloped acreage (including both leases and concessions) held at December 31, 2015 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore	1,294	874	1,050	665
Deepwater Gulf of Mexico	100	39	488	329
Total United States	1,394	913	1,538	994
International				
Equatorial Guinea	284	118	81	30
Falkland Islands	—	—	10,202	3,683
Cameroon	—	—	1,084	511
Israel (1)	185	80	605	261
Cyprus (2)	—	—	663	464
United Kingdom	6	1	14	2
Suriname	—	—	2,095	419
Gabon	—	—	671	403
Total International	475	199	15,415	5,773
Total	1,869	1,112	16,953	6,767

(1) Includes approximately 124,000 gross undeveloped acres and 58,000 net undeveloped acres attributable to our Karish and Tanin fields which were subsequently divested in January 2016.

(2) Our working interest for Cyprus undeveloped acreage decreased from 70% as of December 31, 2015, to 35% upon closing of the sale of a 35% interest in the Cyprus undeveloped acreage to BG Group during 2016.

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.

Future Acreage Expirations If production is not established or we take no other action to extend the terms of the leases, licenses, or concessions, undeveloped acreage will expire over the next three years as follows. No material quantities of PUD reserves were associated with the expiring acreage.

	Year Ended December 31,					
	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US [1]	230	143	137	90	170	47
Deepwater Gulf of Mexico	47	23	7	7	133	91
Equatorial Guinea	—	—	55	19	—	—
Falkland Islands	280	210	3,587	1,255	6,335	2,217
Israel [2]	296	132	—	—	—	—
Cyprus [3]	568	397	—	—	—	—
Cameroon [4]	458	214	—	—	—	—
Suriname	—	—	—	—	2,095	419
Gabon	—	—	—	—	671	403
Total	1,879	1,119	3,786	1,371	9,404	3,177

(1) Approximately 25% of 2016 gross acreage is located in core areas where we currently expect to continue development activities and/or extend the lease terms.
(2) We currently intend to extend certain leases prior to expiration in accordance with license terms. Approximately 99,000 gross acres (47,000 net) will expire and not be extended.
(3) Will expire in accordance with the terms of the Exploitation License for the Aphrodite field.
(4) The acreage represents the Tilapia PSC. We extended the lease during 2015. However, the extension timeline varies and it is therefore unknown what percentage of acreage will be relinquished in 2016.

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, 2015							
United States	1.5	4.0	5.5	212.5	—	212.5	218.0
Falkland Islands	—	0.4	0.4	—	—	—	0.4
Equatorial Guinea	—	—	—	0.3	—	0.3	0.3
Cameroon	—	0.5	0.5	—	—	—	0.5
Total	1.5	4.9	6.4	212.8	—	212.8	219.2
Year Ended December 31, 2014							
United States	1.5	3.1	4.6	319.1	0.7	319.8	324.4
Total	1.5	3.1	4.6	319.1	0.7	319.8	324.4
Year Ended December 31, 2013							
United States	5.8	—	5.8	341.7	3.9	345.6	351.4
Equatorial Guinea	—	—	—	—	—	—	—
Israel	0.4	—	0.4	—	—	—	0.4
Nicaragua	—	0.7	0.7	—	—	—	0.7
China	—	—	—	1.7	—	1.7	1.7
Total	6.2	0.7	6.9	343.4	3.9	347.3	354.2

In addition to the wells drilled and completed in 2015 included in the table above, wells that were in the process of drilling or completing at December 31, 2015 were as follows:

	Exploratory[1]		Development[2]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2	1.0	192	113.2	194	114.2
Cameroon	1	0.5	—	—	1	0.5
Cyprus	2	1.4	—	—	2	1.4
Equatorial Guinea	9	4.2	—	—	9	4.2
Israel [3]	7	3.0	—	—	7	3.0
Total	21	10.1	192	113.2	213	123.3

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

(2) Includes wells pending completion activities.

(3) Includes the Karish and Tanin exploratory wells which have been classified as assets held for sale as of December 31, 2015 and were divested in January 2016.

See Item 8. Financial Statements and Supplementary Financial Data – Note 6. Capitalized Exploratory Well Costs for additional information on suspended exploratory wells.

Oil Spill Response Preparedness In the US, we maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico and Marine Spill Response Corporation, the largest, dedicated oil spill and emergency response organization in the US. For well capping and containment services we have contracted with HWCG, who has contracted with Helix Energy Solutions Group (HESG) for the provision of subsea intervention, containment, capture and shut-in capacity for deepwater Gulf of Mexico exploratory wells. The system, known as the Helix Fast Response System (HFRS), at full production capacity, is designed to contain well leaks up to 55 MBbl/d of oil and 95 MMcf/d of natural gas, at 10,000 pounds per square inch (psi) in water depths to 10,000 feet. Resources also include 15,000 psi-gauge and 10,000 psi-gauge intervention capping stacks designed to shut-in wells in water depths to 10,000 feet. We have entered into a separate utilization agreement with HESG which specifies the asset day rates should the HFRS system be deployed.

Internationally, we maintain membership in Oil Spill Response Limited (OSRL). OSRL is an industry owned cooperative which exists to ensure effective response to oil spills wherever they occur. OSRL is an industry leader in oil spill preparedness and response services. Three supplemental agreements have been executed with OSRL, two of which are focused on well capping and containment services. These agreements allow access to four capping stacks geographically distributed around the world. Resources include two 15,000 psi-gauge and two 10,000 psi-gauge intervention capping stacks designed to shut-in wells in water depths to 10,000 feet. The third supplemental agreement provides access to the Global Dispersant Stockpile, a globally distributed 5,000 cubic meter dispersant stockpile. We also maintain agreements internationally with National Response Corporation, which provides leased response equipment as well as oil spill response services. Additionally, in Equatorial Guinea, we are members of the Oil and Gas Operators Emergency Resource Allocation Group which shares equipment and resources in the event of a spill.

Domestic Marketing Activities Crude oil, natural gas, condensate and NGLs produced onshore US and in the deepwater Gulf of Mexico are sold under short-term and long-term contracts at market-based prices adjusted for location and quality. Onshore production of crude oil and condensate are distributed through pipelines and by trucks and rail cars to gatherers, transportation companies and refineries. Gulf of Mexico production is distributed through pipelines.

Certain onshore US areas in which we operate have had minimal infrastructure in place for the processing and transportation of our production. Company and third party infrastructure projects that came online in 2015 have improved flow assurance and future projects coming online in the northeast in the next few years are expected to continue to enhance transportation of Marcellus Shale production to end markets.

International Marketing Activities Our share of crude oil and condensate from the Aseng and Alen fields is sold at market-based prices to Glencore Energy UK Ltd (Glencore Energy) under a long-term sales contract through 2018. Our share of crude oil and condensate from the Alba field is sold to Glencore Energy under a short-term sales contract, subject to renewal. These products are transported by tanker.

Natural gas from the Alba field is sold for $0.25 per MMBtu to a methanol plant, an LPG plant and an unaffiliated LNG 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 of accounting.

In Israel, we sell natural gas from the Tamar and Mari-B fields, and have agreements with multiple customers to sell natural gas under long-term contracts, ranging from 15 to 17 years. See Delivery Commitments, below.

Delivery and Firm Transportation Commitments Some of our contracts specify the delivery or transportation of fixed and determinable quantities.

Domestic Contracts We have commitments to deliver approximately 437 Bcf of natural gas produced onshore US, primarily in the Marcellus Shale to customers under long-term sales contracts ranging from one to 25 years. We have also entered into various long-term gathering, processing and transportation contracts for some of our onshore US natural gas production. These contracts may commit us to deliver minimum volumes and require us to make payments for any shortfalls in delivering or transporting the minimum volumes under the commitments.

We may use long-term contracts such as these to provide flow assurance for production in over-supplied markets with limited infrastructure, such as the Marcellus Shale, to enable our production to reach higher priced out-of-basin markets. Contracts such as these support continued development of our Marcellus Shale core asset and position us to take advantage of future market growth.

As properties are undergoing development activities, we may experience temporary delivery or transportation shortfalls until production volumes grow to meet or exceed the minimum volume commitments. During 2015, we incurred expense of approximately $33 million related to these commitments. We expect to continue to incur deficiency and/or unutilized costs in the near-term as development activities continue. Should commodity prices continue to decline or we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes and we could be required to make significant payments in the event that these commitments are not otherwise offset.

Although long-term shortfalls are unknown, we continually seek to optimize any short-term under-utilized assets through capacity release and third-party arrangements. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Contractual Obligations.)

Israel Natural Gas Sales and Purchase Agreements We currently sell natural gas from our producing fields offshore Israel to the Israel Electric Corporation (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 a 15 to 17 year period. Some of the contracts provide for increase or reduction in total quantities, and some contracts are interruptible during certain contract periods. Sales prices may be based on an initial base price subject to price indexation over the life of the contract and have a contractual floor. The IEC contract provides for price reopeners in the eighth and eleventh years with limits on the increase/decrease from the contractual price.

Under the contracts, we and our partners have a financial exposure in the event we cannot fully deliver the contract quantities. This exposure is capped by contract and will be reflected as a reduction in sales price for periods in which we are delivering partial contract quantities, or as a direct payment to the customer under certain circumstances and with a cap. The cap is subject to force majeure considerations. We believe that any such sales price adjustments or direct payments would not have a material impact on our earnings or cash flows.

As of December 31, 2015, a total of approximately 5.5 Tcf, gross (1.985 Tcf, net), of natural gas remained to be delivered under the contracts. As of December 31, 2015, we have recorded 2.3 Tcf, net, of proved natural gas reserves, including proved developed reserves of 1.9 Tcf, net, and PUD reserves of 425 Bcf, net, for offshore Israel. Based on current production levels, our available quantities of proved developed reserves are more than sufficient to meet near-term delivery commitments.

Significant Purchasers Glencore Energy was the largest single non-affiliated purchaser of 2015 production and purchased our share of crude oil and condensate production from the Alba, Aseng and Alen fields in Equatorial Guinea. Sales to Glencore Energy accounted for 18% of 2015 total crude oil, natural gas and NGL sales, or 30% of 2015 crude oil sales. Shell Trading (US) Company and Shell International Trading and Shipping Limited (collectively, Shell) purchased crude oil and condensate domestically from the deepwater Gulf of Mexico and the DJ Basin area and internationally from the North Sea. Sales to Shell accounted for 11% of 2015 total crude oil, natural gas and NGL sales, or 18% of crude oil sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil, natural gas and NGL sales in 2015. We maintain credit insurance associated with specific purchasers and believe that the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Hedging Activities Commodity prices continued to be volatile in 2015 and are affected by a variety of factors beyond our control. We use derivative instruments to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil, natural gas and NGLs. As a result of hedging, a portion of near-term cash flow volatility is reduced, which allows us to plan our financial commitments and support our capital investment programs.

We exercise strong management of our hedging program with strong oversight by our Board of Directors. For additional information, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Regulations

Exploration for, and production and marketing of, crude oil, natural gas and NGLs are extensively regulated at the federal, state, and local levels in the US, and internationally. Crude oil, natural gas and NGL development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including, among others, allowable rates of production, transportation, prevention of waste and pollution, and protection of the environment. Laws 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.

Our ability to economically produce and sell crude oil, natural gas and NGLs is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the US and laws and regulations of foreign nations. Many of these 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. These laws, regulations and orders may restrict the rate of crude oil, natural gas and NGL 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.

Internationally, our operations are subject to legal and regulatory oversight by energy-related ministries or other agencies of our host countries, each having certain relevant energy or hydrocarbons laws. Examples include:

- the Ministry of Mines, Industry and Energy which, under such laws as the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea, regulates our exploration, development and production activities offshore Equatorial Guinea;
- the Ministry of National Infrastructures, Energy and Water Resources which regulates our exploration and development activities offshore Israel and the Israeli electricity market into which we sell our natural gas production;
- the Israeli Antitrust Commission which reviews Israel's domestic natural gas sales and ownership in offshore blocks and leases;
- the Ministry of Energy, Commerce, Industry and Tourism which regulates our exploration and development activities offshore Cyprus;
- the Department of Energy and Climate Change which regulates our activities in the UK sector of the North Sea; and
- the Department of Mineral Resources which regulates our exploration activities offshore the Falkland Islands.

Examples of US federal agencies with regulatory authority over our exploration for, and production and sale of, crude oil, natural gas and NGLs include:

- the Bureau of Land Management (BLM), the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), which under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act, have certain authority over our operations on federal lands and waters, particularly in the Rocky Mountains and deepwater Gulf of Mexico;
- the Office of Natural Resources Revenue, which under the Federal Oil and Gas Royalty Management Act of 1982, has certain authority over our payment of royalties, rentals, bonuses, fines, penalties, assessments, and other revenue;
- the US Environmental Protection Agency (EPA) and the Occupational Safety and Health Administration (OSHA), which under laws such as the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, and the Occupational Safety and Health Act have certain authority over environmental, health and safety matters affecting our operations;
- the US Fish and Wildlife Service (FWS) and US National Marine Fisheries Service, which under the Endangered Species Act have authority over activities that may result in the take of any endangered or threatened species or its habitat;
- the US Army Corps of Engineers, which under the Clean Water Act has authority to regulate the construction of structures involving the fill of certain waters and wetlands subject to federal jurisdiction, including well pads, pipelines and roads;
- the Federal Energy Regulatory Commission (FERC), which under laws such as the Energy Policy Act of 2005 has certain authority over the marketing and transportation of crude oil, natural gas and NGLs we produce onshore and from the deepwater Gulf of Mexico; and
- the Department of Transportation (DOT), which has certain authority over the transportation of products, equipment and personnel necessary to our onshore US and deepwater Gulf of Mexico operations.

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 are traded.

Among the laws affecting our operations are the following:

Environmental Matters As a developer, owner and operator of crude oil and natural gas properties, we are subject to various federal, state, local and foreign host country laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must 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, prevention of and responses to leaks and spills, and the remediation of petroleum-product contamination. 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 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.

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 designated as hazardous and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

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 we have, to date, expended material amounts in connection with such activities or 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.

The following is a summary of the more significant US environmental developments and requirements that may affect our operations.

Various state and federal statutes such as the Endangered Species Act (ESA) prohibit certain actions that adversely affect endangered or threatened species and their habitat, wetlands, migratory birds, marine mammals, or natural resources. Where the taking or harm of such species occurs or may occur, or where damages to wetlands or natural resources may occur, the government or private parties may act to prevent crude oil and natural gas exploration activities. In particular, a federal or state agency could order a complete halt to drilling activities in certain locations or during certain seasons when such activities could result in a serious adverse effect upon a protected species. 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. In April 2015, for example, the FWS announced that it was listing the northern long-eared bat as threatened under the ESA, which could have an impact on the timing of certain of our operations in the Marcellus Shale. Listing of the Lesser Prairie Chicken likewise could impact our operations in the Permian Basin. In September 2015, a federal court invalidated the FWS's listing of the Lesser Prairie Chicken as threatened because the FWS failed to give proper consideration to voluntary conservation measures; however, the government has asked the court to instead return the listing to the FWS for further consideration and indicated it would restore the Lesser Prairie Chicken to the list of endangered and threatened wildlife.

In May 2015, the US Environmental Protection Agency and the US Army Corps of Engineers jointly released a final rule that is meant to define more precisely which water bodies are and are not subject to the Clean Water Act (the Clean Water Rule). Among other things, the Clean Water Rule defines the intermittent, ephemeral, and man-altered streams to be protected and specifies when federal jurisdiction may be extended from a covered water to nearby waters. While the agencies have claimed that the new requirements are narrower than existing regulation, the Clean Water Rule has generated substantial controversy. Several court challenges have been filed, and legislation has been introduced in Congress to require changes. To the extent that the Clean Water Rule requires more detailed studies of site conditions, or results in an expansion of federal jurisdiction over streams and wetlands, our costs may increase, especially with respect to spill prevention, storm water management, and wetlands permitting. We are continuing to monitor the challenges and to evaluate the impact of the new rule on our operations.

There also have been a series of recent air regulations and proposals that affect, or that may affect, our operations. In 2012, for example, the EPA issued New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants to control air emissions associated with crude oil, natural gas and NGL production, including natural gas wells that are hydraulically fractured. In addition to addressing emissions from storage tanks and other equipment, those regulations required technologies and processes that, while reducing emissions, enable companies to collect additional natural gas that can be sold. Specifically, as of January 2015, owners and operators of natural gas wells must use emissions reduction technology called "green completions," technologies that were already widely deployed at wells. To date, those rules have had minimal impact on our business since the reduction of GHG emissions already was one of our priorities and we had been working to improve our methods to reduce GHGs through operational and business practices. For example, we have undertaken emission reduction projects such as our US Vapor Recovery Unit (VRU) program, where we have installed VRUs to capture natural gas that would otherwise be flared on a substantial number of our tank batteries.

In March 2014, the Obama Administration released a Strategy to Reduce Methane Emissions that includes consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA released five draft white papers on methane emissions, volatile organic compound (VOC) emissions, and emission mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities, and natural gas production and transmission facilities. Building on its white papers and the public input on those documents, the EPA issued a proposed rule in the summer of 2015 that would set additional standards for methane and VOC emissions from new and modified oil and gas production sources, including hydraulically fractured oil wells, and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. An accompanying EPA proposal would clarify when oil and natural gas sites should be aggregated for purposes of air permitting, which could increase our compliance and permitting costs. As another prong of the Administration's methane strategy, BLM is expected to propose standards for reducing venting and flaring on public lands. The Administration's goal is to reduce methane emissions from the oil and gas industry by 40-45% by 2025 as compared to 2012 levels. It also bears noting that substantially all of our onshore US properties are subject to EPA's requirements for reporting annual GHG emissions. Information in such reports could form the basis of further GHG regulations.

In another air development, the EPA announced in October 2015 that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, areas that cannot meet the new standard eventually will need to impose additional requirements on sources of VOCs and other ozone precursors which could increase the cost of siting and operating our facilities.

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

Colorado Examples of such regulation on the operational side include the Greater Wattenberg Area Special Well Location Rule 318A (Rule 318A), which was adopted by the Colorado Oil and Gas Conservation Commission (COGCC) to address oil and gas well drilling, production, commingling and spacing in Wattenberg (located in the DJ Basin). The 2011 amendments to Rule 318A removed the limit on the number of wells which can produce from a particular formation, allowing wellbore spacing units and permitting wells to cross section lines. The amendments also addressed areas such as infill drilling, water sampling and waste management plans.

In February 2013, the COGCC approved setback rules for crude oil and natural gas wells and production facilities located in close proximity to occupied buildings. Previously, the COGCC had allowed setback distances of 150 feet in rural areas and 350 feet in high density urban areas. These have been increased to a uniform 500 feet statewide setback 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 to surface owners and the owners of occupied building units. In addition, the rules require advance notice to surface owners, the owners of occupied buildings and local governments prior to the filing of an Application for Permit to Drill or Oil and Gas Location Assessment as well as outreach and communication efforts by an operator.

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. Those statewide rules require sampling of up to four water wells within a half mile radius of a new crude oil and natural gas well before drilling, between six and 12 months after completion, and between five and six years after completion. For the Greater Wattenberg Area, the COGCC requires operators to sample only one water well per quarter governmental section before drilling and between six to 12 months after completion. 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, 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 Colorado Department of Public Health and Environment has extended the EPA's emissions standards for crude oil and natural gas operations to directly control methane. The final rules, which cover the life cycle of oil and gas development, production, and maintenance, reflect a collaborative effort by the Environmental Defense Fund, Noble Energy and other oil and gas operators.

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. However, a few localities in Colorado have prohibited certain exploration and production activities, particularly use of hydraulic fracturing within their boundaries. See Hydraulic Fracturing, below.

In 2014, by executive order, Colorado Governor Hickenlooper created the Task Force on State and Local Regulation of Oil and Gas Operations (Task Force) for the purpose of recommending policies and legislation. The 21-member Task Force, which included a Noble Energy representative, concluded its activities on February 27, 2015. The Task Force sent nine recommendations to the governor. The recommendations sought to balance land use issues among communities and oil and gas operators and allow reasonable access to private mineral rights. Three recommendations were approved by the legislature, and state regulators proposed two rules covering siting large oil and gas operations in urban areas and coordination of drilling with local governments. We currently are evaluating the proposals.

Pennsylvania Pennsylvania's Act 13 of 2012 (Act 13) represented the first comprehensive legislation regarding the development of the Marcellus Shale in Pennsylvania. Act 13, among other things, enacted stronger environmental standards; established impact fees, which are set based on a multi-year fee schedule and the average price of natural gas; increased the notice distance for unconventional well permit applications from 1,000 feet to 3,000 feet; extended the setback distance for unconventional wells from 200 feet to 500 feet; and increased the distance and duration of presumed liability for water pollution to 2,500 feet from a well site and twelve months after well drilling, completion, stimulation or alteration. In addition, Act 13 imposed spill prevention requirements applicable to well site construction, wastewater transportation, and gathering lines. These requirements may result in increased costs and lower rates of return for our Marcellus Shale development project.

In 2013, the Pennsylvania Supreme Court invalidated the portions of Act 13 providing for statewide zoning and state waivers of the setback requirements in Pennsylvania's Oil and Gas Act. In 2014, moreover, the Pennsylvania Commonwealth Court invalidated Act 13's provisions allowing the state to review local drilling rules. These court decisions have the effect of giving local communities in Pennsylvania more authority to regulate oil and gas operations, which could make it more difficult to develop our Marcellus Shale acreage in some municipalities. Furthermore, the state has been moving to finalize new rules for surface operations at oil and gas sites that, among other things, would increase public participation in the permitting process, increase mitigation obligations and require surveys for abandoned wells.

West Virginia In December 2011, the West Virginia legislature passed, and the governor signed, the Natural Gas Horizontal Well Control Act, which, among other things, provides for increased well permit fees, well location restrictions, development of well site safety and water management plans, and public notice requirements.

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.

In May 2013, the Texas Railroad Commission (RRC) issued an updated "well integrity rule" that addresses requirements for drilling, casing and cementing wells. The rule also includes new testing and reporting requirements, including clarifying that cementing reports must be submitted after well completion or after cessation of drilling, whichever is earlier.

In October 2014, the RRC adopted new 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.

Other US Environmental Requirements In addition to the above, we will continue to monitor proposed and new legislation and regulations in all our operating jurisdictions to assess the potential impact on the Company. Concurrently, we are engaged in extensive public education and outreach efforts with the goal of engaging and educating the general public and communities about the energy, economic and environmental benefits of safe and responsible crude oil and natural gas development.

US Offshore Regulatory Developments In April 2015, the BSEE issued a proposed rule entitled "Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Blowout Preventer Systems and Well Control," which is intended to update standards for blowout prevention systems and other well controls for offshore oil and gas activities conducted in US federal waters, including the Gulf of Mexico. The proposed rule is significant in both the scope of its requirements and its potential impact. It would impose significant new requirements relating to well design, well control, casing, cementing, real-time well monitoring and subsea containment. It would also significantly revise provisions relating to drilling, workover, completion and decommissioning activities. If adopted as proposed, the new rule would likely increase the costs associated with well design, drilling and completion operations and may require the temporary shut-in of existing offshore wells in federal waters while work is done to bring them into compliance with the new rule, which could adversely impact our existing and planned operations in the Gulf of Mexico. Final rules are expected to be issued in 2016.

Additionally, the BOEM is in the process of updating its regulations and program oversight to establish more robust risk management, financial assurance and loss prevention requirements for oil and gas operations in the Outer Continental Shelf, including the Gulf of Mexico. The proposed revisions are intended to enable the BOEM to better assess the risk management and financial capabilities of both operators and owners of oil and gas interests in the Outer Continental Shelf. As part of this effort, in September 2015, BOEM announced that it would be making changes to the agency's guidance criteria for determining an entity's financial ability to carry out decommissioning obligations on the Outer Continental Shelf. The revised regulatory framework that the BOEM ultimately adopts could, among other things, expand the classes of interested parties that are required to post financial assurances in favor of the BOEM (such as operating and/or non-operating interest owners previously exempt from posting such financial assurances, ORRI holders and secured lenders) and increase the amounts of the required coverage for offshore oil and gas operations, which could significantly increase the costs associated with our activities in the Gulf of Mexico. Final guidance is expected to be issued in 2016.

See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.*

Israel's Natural Gas Policy and Antitrust Authority See Items 1. and 2. Business and Properties – *Update on Israel*.

Impact of Dodd-Frank Act Derivatives Regulation The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market. We have determined that we qualify as a "non-financial entity" for purposes of the end-user exception and satisfy the other requirements of the end-user exception. As a result, our hedging activity will not be subject to mandatory clearing. We do not expect to clear our swaps, and our swap transactions will not be subject to the margin requirements imposed by derivatives clearing organizations. In addition, Section 302(a) of the Terrorism Risk Insurance Program Reauthorization Act of 2015 excludes end users who are exempt from mandatory clearing, such as us, from any margin requirements imposed by rules ultimately adopted by the CFTC.

While we will not directly experience significant burdens from the changes in the regulation of swaps, some of our counterparties may. If so, this could result in certain market participants deciding to curtail or cease their derivatives activities. While many regulations have been promulgated and are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business cannot be determined at this time.

Impact of Dodd-Frank Act Section 1504 Section 1504 of the Dodd-Frank Act requires disclosure of certain payments made by resource extraction companies to a foreign government or the US federal government for the commercial development of oil, natural gas or minerals. The Dodd-Frank Act mandates that the SEC promulgate rules to implement this disclosure requirement. On December 11, 2015, the SEC proposed resource extraction issuer payment disclosure rules that, if adopted, would require resource extraction companies, such as us, to publicly file information about the type and total amount of payments made for each project related to the commercial development of oil, natural gas or minerals, and the type and total amount of payments made to each government.

Hydraulic Fracturing

Concerns The practice of hydraulic fracturing, especially the hydraulic fracturing processes associated with drilling in shale formations, is the subject of significant focus among some environmentalists and regulators. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment and, potentially, the general public health, have been raised at local, state and federal levels of government in the US and internationally. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of both water supply sources and disposal methods.

Our Operations Hydraulic fracturing techniques have been used by the industry since 1947, and, currently, more than 90% of all crude oil and natural gas wells drilled in the US employ hydraulic fracturing. 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.

Where possible, we strive to procure non-hydrologic water (water that is not connected to a natural surface stream) for use in hydraulic fracturing; a large proportion of our water is from non-tributary sources, such as deep ground water. In the DJ Basin, we are in the process of securing additional water rights in support of our drilling program, and we engage in significant water recycling efforts in both the DJ Basin and Marcellus Shale. 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.

Studies and Potential Rulemaking Although hydraulic fracturing is regulated primarily at the state level, governments and agencies at all levels from federal to municipal are studying it and evaluating the need for further requirements. For example, in 2011, the US Secretary of Energy formed the Shale Gas Production Subcommittee (Subcommittee), a subcommittee of the Secretary of Energy Advisory Board. The Subcommittee issued final recommendations in November 2011 that included better communications with the public, better air quality controls, protection of water supply and quality, disclosure of fracturing fluid composition, reduction of diesel fuel use, continuous development of best practices, and federal sponsorship of research and development with respect to unconventional gas.

In addition, the US Department of Energy's National Energy Technology Laboratory (NETL) is conducting a comprehensive assessment of the environmental effects of shale gas production at two industry-provided Marcellus Shale test sites in southwestern Pennsylvania. Goals include:

- documentation of environmental changes that are coincident with shale gas production;
- development of technology or management practices that mitigate any unintended environmental changes; and
- development of monitoring technologies to (1) assess the impact of shale gas production on air quality and (2) determine if zonal isolation between producing formations and drinking water aquifers is maintained after hydraulic fracturing.

We are monitoring the results of the NETL study in order to assess any potential impact on our onshore US development programs.

Also in June 2015, the US EPA issued its draft "Assessment of the 17 Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources." At a high level, the agency states, "[it] did not find evidence that hydraulic fracturing mechanisms have led to widespread, systemic impacts on drinking water resources in the United States." The agency's Science Advisory Board (SAB) recently commented however, that the agency's conclusions do not clearly describe the systems of interest (e.g., groundwater, surface water) nor the definitions of "systemic," "widespread," or "impacts." The SAB has also raised a concern that the agency's conclusions do not reflect "the uncertainties and data limitations described in the body of the Report associated with such impacts." The SAB has suggested the agency revise the major statements of findings in the Executive Summary and elsewhere in the draft Assessment Report to be more precise, and to clearly link these statements to evidence provided in the body of the draft Assessment Report. The SAB also recommends that the EPA discuss the significant data limitations and uncertainties, as documented in the body of the Report, when presenting the major findings. EPA has not yet responded to the SAB.

Also on the regulatory front, the US BLM issued proposed regulations in 2012 for hydraulic fracturing on federal lands, which were withdrawn and then reissued on May 16, 2013. The proposed rules would affect drilling operations on the 700 million acres of federally-owned minerals administered by the BLM, as well as 56 million acres of Native American-owned minerals. A final rule was released in March, 2015, and was immediately challenged in U.S. district court in Wyoming. The judge issued a preliminary injunction in September agreeing with claims that the BLM may lack statutory authority for the rule. The agency was ordered by the court to provide a complete administrative record, which it says it will comply with by January 2016. The agency has also asked the 10th Circuit Court of Appeals to overturn the lower court's preliminary injunction, which is pending.

Apart from its air regulations for newly fractured natural gas wells (see Regulations), the EPA developed new guidelines under the Safe Drinking Water Act regarding the issuance of permits for the use of diesel fuel as a component in hydraulic fracturing activities. The guidance outlines for EPA permit writers, where EPA is the permitting authority, requirements for diesel fuels used for hydraulic fracturing of wells, technical recommendations for permitting those wells, and a description of diesel fuels subject to EPA underground injection control permitting. Beyond that, the agency has solicited public comment on information reporting and disclosure for hydraulic fracturing. The EPA also is planning to develop a rule addressing discharges of hydraulic fracturing wastewaters from oil and gas extraction facilities to public treatment works.

In June 2012, OSHA and the National Institute of Occupational Safety and Health (NIOSH) issued a joint hazard alert for workers who use silica (sand) in hydraulic fracturing activities. The following year saw the agency formally propose to lower the permissible exposure limit for airborne silica. OSHA also has prepared guidance identifying additional workplace hazards resulting from hydraulic fracturing and ways to reduce exposure to those hazards.

To date, hydraulic fracturing has been regulated primarily at the state level, and all of the states where our US core onshore operations are located (including Colorado, Texas, West Virginia, and Pennsylvania) have developed such requirements. See Regulations. In 2012, moreover, several local communities in Colorado became interested in increasing regulatory requirements on oil and gas development. The most notable situation occurred in the City of Longmont, Colorado in 2012 where voters chose to ban hydraulic fracturing activities within city limits.

In 2013, the municipalities of Broomfield, Fort Collins and Lafayette each passed similar ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries. Challenges were brought against each of these bans in state district court and industry has prevailed in Longmont and Fort Collins. The cities have appealed to the Colorado Supreme Court, which held oral arguments in December 2015, and is expected to rule on the legality of municipal bans sometime in the first half of 2016. The litigation in Broomfield is stayed pending resolution of the Supreme Court Appeal, and the City of Lafayette has dropped their ban. Another measure to ban hydraulic fracturing was on the ballot in the City of Loveland in northern Colorado in June of 2014, but the oil and gas industry worked with the community to defeat that initiative. Likewise, in January 2015, the Board of Trustees for the Town of Erie, Colorado voted not to impose a moratorium on new crude oil and natural gas wells. The large majority of our DJ Basin acreage is not located in the municipalities that have attempted to prevent oil and gas operations; therefore, we do not expect our operations to be materially impacted by these developments.

However, in the future, should additional statewide or local Colorado initiatives be undertaken to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations, our business could be impacted, resulting in delay or inability to develop oil and gas reserves, reducing our long-term reserves, production and cash flow growth, and potentially having a negative impact on our stock price. For example, a number of statewide ballot initiatives have been proposed for the upcoming 2016 election that would unreasonably restrict or limit crude oil and natural gas development in Colorado. The proposed measures call for a statewide ban on hydraulic fracturing, mandatory drilling setbacks ranging between 2,500 and 4,000 feet, and local and municipal control over regulation of the industry. These ballot initiatives are subject to titling and Colorado Supreme Court review and other qualifying requirements. The ultimate passage and implementation of any of these initiatives could have a negative impact on our business. In particular, a statewide ban on hydraulic fracturing or imposition of unreasonable drilling setbacks will likely delay or otherwise limit our drilling and development activities in certain parts of the DJ Basin. This could result in a reduction in our proved reserves and negatively impact our results of operations, cash flows, and stock price.

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

Public Disclosure Several states have issued regulations requiring disclosure of certain information regarding the components used in the hydraulic-fracturing process. In 2011, for example, the RRC adopted the Hydraulic Fracturing Chemical Disclosure rule, which requires companies to disclose, on a public registry, chemical ingredients used to hydraulically fracture wells in Texas. The registry, FracFocus.org, is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council. In December 2011, the COGCC adopted hydraulic fracturing fluid ingredient regulations requiring disclosure of all chemicals and establishing ways to protect proprietary information. The regulations allow disclosure through the FracFocus web site. The State of Wyoming also requires disclosure of the types and amounts of chemicals. In 2012, through legislation known as Act 13, Pennsylvania established a requirement that operators submit information regarding hydraulic fracturing chemicals to FracFocus.org. Other states have proposed, or are considering, similar regulations which require specific disclosures by operators and/or outline requirements for construction and operation of wells and monitoring of well activity. We are currently providing disclosure information on FracFocus.org for all onshore US areas in which we operate.

Additional Information See:

- Items 1. and 2. Business and Properties – Regulations;
- Item 1A. Risk Factors; and
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Risk and Insurance Program.

Undeveloped Oil and Gas Leases Oil and gas exploration is a lengthy process of obtaining data, evaluating, and de-risking prospects, and it takes time to develop resources in a responsible manner. The period of time from lease acquisition to discovery can take many years of ongoing effort.

We begin by leasing acreage (or deepwater lease blocks) from individuals, other operators or the host government. It may take years for us to assemble sufficient acreage to cover the areal extent of a prospect that we wish to explore.

Once the acreage position is assembled, we obtain seismic data either through purchase of available data or by contracting for seismic services. Our exploration staff then begin a lengthy process of analyzing the seismic and other data in order to identify a potential optimal location for drilling an initial exploratory well. Once we decide to drill an exploratory well, we must obtain permits and contract a drilling rig with the specifications for the depth and well pressures which we expect to drill.

For example, in 2012, we entered the Falkland Islands through a farm-in agreement of the Northern and Southern Area Licenses with a 35% working interest in approximately 10 million gross acres. Later that year, we participated in an initial non-operated exploratory well, the Scotia well located in the Northern License, which was drilled and permanently plugged and abandoned after finding noncommercial amounts of hydrocarbons. In 2013 and 2014, we assumed operatorship and continued to acquire and process 3D seismic information for both licenses, which our exploration staff analyzed and used to plan an initial operated drilling program. We drilled the Humpback exploration prospect, located in the South Falkland Basin in 2015 but did not locate commercial quantities of hydrocarbons. In the North Falkland Basin, we identified the Rhea prospect (75% operated working interest) as the initial target. However, we experienced material operational issues with the drilling unit while drilling the Humpback well and the drilling contract was terminated on February 11, 2016. We remain confident in the potential of the Rhea prospect, which is located near the Sea Lion discovery in a proven petroleum system. We have been and will continue to work closely with our partners and the Falkland Islands Government to evaluate a path forward that includes retaining flexibility for the Rhea exploration well.

If there is a discovery, we may need to obtain additional data and/or drill appraisal wells in order to estimate the extent of the reservoir and the volume of resources that could potentially be recovered. Appraisal or development drilling requires additional time to contract for an appropriate drilling rig, and obtain pipe, other equipment, and supplies.

We strive to maintain an appropriate inventory of onshore and offshore exploration prospects suitable to our experience as an operator, financial resources, and current development timeline.

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. See Item 1A. Risk Factors.

Geographical Data

We have operations throughout the world and manage our operations by region. Information is grouped into four components that are all primarily in the business of crude oil, natural gas and NGL exploration, development and production: United States, West Africa, Eastern Mediterranean, and Other International and Corporate. See Item 8. Financial Statements and Supplementary Data – Note 15. Segment Information.

Employees

As of December 31, 2015, we had 2,395 full-time employees. The 2015 year-end employee count includes 340 foreign nationals working as employees primarily in Israel, Cyprus, Equatorial Guinea and Cameroon. We regularly use independent contractors and consultants to perform various field and other services.

Offices

Our principal corporate office is located at 1001 Noble Energy Way, Houston, Texas, 77070. We maintain additional offices in Denver, Colorado; Greeley, Colorado; Canonsburg, Pennsylvania; Washington, D. C.; and in Cameroon, Equatorial Guinea, Israel, Cyprus, Mexico, Falkland Islands and the Netherlands.

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.

Furthermore, while the majority of our assets are held by production, certain of our assets, such as our Eagle Ford Shale and Permian Basin properties, are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas and failure to meet these obligations may result in the loss of a lease.

Title Defects Subsequent to a lease or fee interest acquisition transaction, such as our Marcellus Shale acquisition in 2011, 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. Curative efforts for remaining uncured defects related to the Marcellus Shale acreage are ongoing. Options to address uncured title defects include a reduction in the remaining amount of the CONSOL Carried Cost Obligation, an indemnity agreement, or the transfer of additional interests.

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 natural gas 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.

Risk Management

The oil and gas business is subject to many significant risks, including operational, strategic, financial and compliance/ regulatory risks. We strive to maintain a proactive enterprise risk management (ERM) process to plan, organize, and control our activities in a manner which is intended to minimize the effects of risk on our capital, cash flows and earnings. ERM expands our process to include risks associated with accidental losses, as well as operational, strategic, financial, compliance/regulatory, and other risks.

Our ERM process is designed to operate in an annual cycle, integrated with our long range plans, and supportive of our capital structure planning. Elements include, among others, cash flow at risk analysis, credit risk management, a commodity hedging program to reduce the impacts of commodity price volatility, an insurance program to protect against disruptions in our cash flows, a robust global compliance program, and government and community relations initiatives. We benchmark our program against our peers and other global organizations. See Item 1A. Risk Factors for a discussion of specific risks we face in our business.

Available Information

Our website address is *www.nobleenergyinc.com.* Available on this website under "Investors – 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 "About Us – Corporate Governance", and available in print upon request made by any stockholder to the Investor Relations Department, are charters for our Audit Committee, Compensation, Benefits and Stock Option Committee, Corporate Governance and Nominating Committee, and Environment, Health and Safety 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 "Corporate Governance" 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. In addition, the current global economic and political environment intensifies many of these risks.

We are currently experiencing a severe downturn in the oil and gas business cycle, and an extended or more severe downturn could have material adverse effects on our operations, our liquidity, and the price of our common stock.

Our ability to operate profitably, maintain adequate liquidity, grow our business and pay dividends on our common stock depend highly upon the prices we receive for our crude oil, natural gas, and NGL production. Commodity prices are volatile. Crude oil prices, in particular, began to decline significantly in the fourth quarter 2014, declined further in 2015 and have continued to trade at a low level or decline further thus far in 2016.

High and low monthly daily average prices for crude oil and high and low contract expiration prices for natural gas for the last three years and into 2016 were as follows:

	Jan. 1 - Feb.12,	Year Ended December 31,		
	2016	2015	2014	2013
NYMEX				
Crude Oil - WTI (per Bbl) High [(1)]	$ 31.78	$ 59.83	$ 105.15	$ 110.53
Crude Oil - WTI (per Bbl) Low [(1)]	29.71	37.33	59.29	86.68
Natural Gas - HH (Per MMbtu) High	2.23	3.19	5.56	4.46
Natural Gas - HH (Per MMbtu) Low	2.05	2.03	3.73	3.11
Brent				
Crude Oil - (per Bbl) High	32.80	64.32	111.76	118.90
Crude Oil - (per Bbl) Low	31.93	38.21	62.91	97.69

(1) Average realized prices for our US NGL production, determined at two primary market centers (Conway and Mt. Belvieu) tend to track the volatility of NYMEX WTI and have also declined.

During 2015, low commodity prices had material negative impacts on our revenues, operating cash flows and profitability, caused us to reduce our capital investment program and led to reductions in the price of our common stock. An extended period of low, or lower, crude oil and natural gas prices could have further material adverse effects on our planned operations, level of capital expenditures and financial condition. In addition, we may not be able to achieve sufficient additional reductions in operating or capital costs or achieve additional drilling and/or operational efficiencies to offset all or a portion of a further decline in commodity prices.

If commodity prices continue to trade for an extended period at the lower levels reached thus far in 2016, or decline further, the following impacts could occur:

- further significant reductions of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically, leading to shut-in or early abandonment of producing wells and increased capital requirements for abandonment operations;
- certain properties in our portfolio becoming economically unviable;
- additional impairments of proved or unproved properties;
- loss of undeveloped acreage if our production is shut-in or we are unable to make scheduled delay rental payments;
- use of cash flow to satisfy minimum take or pay obligations under throughput agreements if production is suspended;
- further reduction, or suspension, of our 2016 capital investment program, or significant reductions in future capital investment programs, resulting in a reduced ability to develop our reserves;
- delay, postponement or cancellation of some of our exploration or development projects;
- inability to meet exploration commitments, leading to loss of leases or exploration rights;
- divestments of properties to generate funds to meet cash flow or liquidity requirements;
- limitations on our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- 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 could increase our 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;
- changes in corporate structure that could lead to loss of key personnel and interrupt our business activities;
- limitations on our access to sources of capital, such as debt and equity; and
- reduction or suspension of dividends on our common stock.

In addition, lower commodity prices, including declines in commodity forward price curves, may result in the following:

- further declines in our stock price;
- additional asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment; and
- additional counterparty credit risk exposure on commodity hedges and joint venture receivables.

Our hedging arrangements in place will not fully mitigate the effect of commodity price volatility, and our 2016 revenue and results of operations will be adversely affected if commodity prices remain at current low levels reached thus far in 2016 or decline further. In the current commodity price environment, we are less likely to hedge future revenues to the same extent as our historical and existing hedging arrangements. As such, our revenues will be more susceptible to commodity price volatility as our commodity price hedges settle and are not replaced.

Historically, the markets for crude oil, natural gas, and NGLs have been volatile and are likely to continue to be volatile in the future. Markets and prices for crude oil, natural gas and NGLs depend on factors beyond our control, factors including, among others:

- economic factors impacting gross domestic product growth rates of countries around the world;
- global demand for crude oil, natural gas and NGLs;
- Organization of Petroleum-Exporting Countries (OPEC) spare capacity relative to global crude oil supply and crude oil pricing strategies;
- global factors impacting supply quantities of crude oil, natural gas and NGLs, including US crude oil and NGL supply, and the possible addition of Iranian crude oil supplies to world markets and/or new natural gas supplies;
- technology advances that increase crude oil, natural gas and NGL production;
- developments in the domestic and global crude oil markets due to the lifting of the US crude oil export ban;
- developments in the global LNG market, including exports from the US;
- actions taken by foreign hydrocarbon-producing nations;
- geopolitical conditions and events, including generational leadership or regime changes, outcomes of presidential elections, changes in government energy policies, or instability/armed conflict in hydrocarbon-producing regions;

- the existence of government imposed price controls and/or product subsidies;
- fluctuations in US dollar exchange rates, the currency in which the world's crude oil trade is denominated;
- the price and availability of alternative fuels, including coal, solar, wind, nuclear energy and biofuels;
- the long-term impact on the crude oil market of the use of natural gas as an alternative fuel for road transportation;
- the availability of pipeline capacity and infrastructure;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- the effectiveness of worldwide conservation measures;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- demand for electricity as well as natural gas used as fuel for electricity generation;
- fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and its impacts on crude oil demand as a transportation fuel;
- access to government-owned and other lands for exploration and production activities; and
- domestic and foreign governmental regulations and taxes.

Failure to effectively execute our major development projects could result in significant delays and/or cost over-runs, damage to our reputation, and limitations on our growth with negative impact on our operating results, liquidity and financial position.

We currently have an inventory of major development projects in various stages of development. Certain of these projects will take several years before first production is achieved. The level of activity necessary to successfully execute our major development projects requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. Offshore projects, for example, often entail significant technical and other complexities including subsea tiebacks to an 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 may not be able to fully execute these projects on schedule and on budget due to:

- a continued low commodity price environment;
- inability to develop a feasible project design;
- lack of government approvals for projects;
- delays obtaining project approvals from joint venture partners;
- delays in obtaining project financing on terms that are acceptable to us and/or our partners;
- changes in Israel's regulatory framework for the development of natural gas resources, which could impact timing of development of the Leviathan project and partner funding;
- potential negative impact of natural gas dispute between Israel and Egypt on Leviathan natural gas marketing activities;
- inability to successfully negotiate natural gas sales and purchase agreements in quantities and at prices to support a final investment decision;
- inability to attract and/or retain a sufficient quantity of personnel with the requisite skills to bring these complex projects to production;
- potential organizational changes and high turnover attributed to current pricing / operating environment may hinder our ability to deliver projects on time;
- significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure;
- civil disturbances, anti-development activities, legal challenges or other potential interruptions which could prevent access or project approval; and
- drilling hazards, accidents or natural disasters.

We may not be able to compensate for, or fully mitigate, these risks.

Our Eastern Mediterranean natural gas marketing activities bear certain geopolitical, regulatory and financial risks that could adversely impact our ability to monetize our Israel and Cyprus natural gas assets.

We have entered into and are currently negotiating various long-term GSPAs for our Eastern Mediterranean natural gas assets including the Tamar, Leviathan, and Aphrodite fields. Some of these agreements require exporting natural gas from either Israel or Cyprus to other countries in the region, such as Egypt and Jordan. These agreements bear a variety of risks, including geopolitical, regulatory and financial elements. War, political violence, or civil unrest could affect both our and our counterparties' abilities to cooperate and to perform under these agreements, and could potentially lead to contract termination. In addition, economic or financial duress of our counterparties could jeopardize their ability to fulfill their payment obligations under these contracts. Furthermore, if material disruptions occur to 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 significant financial losses.

Our international operations may be adversely affected by economic and geopolitical developments.

We have significant international operations, with approximately 32% of our 2015 total consolidated sales volumes coming from our international operations in Equatorial Guinea and Israel. We are also conducting exploration activities in these countries as well as other international areas, including Cameroon, Cyprus, Gabon, Falkland Islands and Suriname. Our operations may be adversely affected by political and economic developments in these areas, including the following:

- renegotiation, modification or nullification of existing contracts, such as 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 result in an increase in 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;
- disruptions caused by territorial or boundary disputes in certain international regions;
- changes in drilling or safety regulations in other countries;
- laws and policies of the US and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- potential for Israel gas production and regional exports to be interrupted by political conditions and events, and regional instability or armed conflict in the region;
- potential decline in bipartisan US support of Israeli government policies which could impact trade with Israel;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- foreign exchange or repatriation restrictions;
- war, piracy, acts of terrorism or civil unrest;
- international monetary fluctuations and changes in the relative value of the US dollar as compared with the currencies of other countries in which we conduct business; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Such political and economic developments as mentioned above 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.

See also Items 1. and 2. Business and Properties – Update on Israel - Israel Natural Gas Framework.

Our operations may be adversely affected by changes in the fiscal regimes and related government policies and regulations in the 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 of these countries could have a significant impact on our operations and financial performance. Further, we cannot predict how government agencies or courts will interpret existing regulations and tax laws or the effect such interpretations could have on our business.

Many governments globally are seeking additional revenue sources, including, potentially, increases in government financial take from oil and gas projects. In developing nations, governments may seek additional revenues to support infrastructure and economic development and for social spending. In many nations of the Organisation for Economic Cooperation and Development (OECD), governments are facing significant budget deficits and growing national debt levels, as well as pressure from financial markets to address structural spending imbalances.

The OECD itself issued guidance reports in October 2015 on Base Erosion and Profit Shifting (BEPS), an initiative which aims to standardize and modernize global tax policy and disclosure of financial and operational data with tax authorities. Adoption of BEPS's recommendations is widely expected by the majority of the foreign jurisdictions in which we operate and this could result in changes to tax policies, including transfer pricing policies. To the extent such changes significantly increase the overall tax imposed on currently producing projects, these projects could become less economic, or wholly uneconomic, thereby reducing the amount of proved reserves we record and cash flows we receive, and possibly resulting in asset impairment charges.

In the US, certain measures have been proposed that would alter current tax expense on oil and gas companies, for example: the repeal of percentage depletion for oil and natural gas properties; the deferral of expensing intangible drilling and development costs (IDC); the inability to expense costs of certain domestic production activities; and a lengthening of the amortization period for certain geological and geophysical expenditures. It is likely that some of these proposals to increase tax expense on the oil and gas industry will continue to be reviewed by the US Congress in future years. The enactment of some or all of these proposals could have a significant negative impact on our capital investment, production and growth.

Changes in fiscal regimes 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;
- reduce exploration activities, which could have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- have a negative impact on the ability of us and/or our partners to obtain financing;
- cause delay in or cancellation of development plans, which could also have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- reduce the profitability of our projects, resulting in decreases in net income and cash flows with the potential to make future investments uneconomical;
- 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;
- restrict our ability to compete with imported volumes of crude oil or natural gas; and/or
- adversely affect the price of our common stock.

See also Items 1. and 2. Business and Properties – Update on Israel - Israel Natural Gas Framework.

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

A significant portion of our production and revenue is highly concentrated and is generated from certain deepwater fields. These fields, located offshore West Africa and in the Eastern Mediterranean, included 13 gross producing wells and contributed approximately 35% of our 2015 total revenues and 32% of our 2015 sales volumes, respectively, and are capital and resource-intensive. Although we carry business interruption insurance in these areas, a disruption, such as from an accident, natural disaster, government intervention or other event, would have a significant impact on our production profile, cash flows, profitability, and overall business plan.

Our operations may be adversely affected by violent acts such as from civil disturbances, terrorist acts, regime changes, cross-border violence, war, piracy, or other conflicts that may occur in regions that encompass our operations.

Violent acts resulting in loss of life, destruction of property, environmental damage and pollution occur around the world. Many incidents are driven by civil, ethnic, religious or economic strife. In addition, the number of incidents attributed to various terrorist or extremist organizations has increased significantly. Certain countries within the Middle East, including Syria, Libya, Iraq and Yemen, continue to experience varying degrees of political instability, public protests and terrorist attacks. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred. 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 our curtailing operations. In the event that regions in which we operate experience civil or political unrest or acts of terrorism, especially in areas where such unrest leads to regime change, our operations in such regions 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:

- increased volatility in global crude oil, natural gas and NGL 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 world 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 or supplies to enter or exit the countries where we are conducting 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 natural gas purchasers leading to interruption of natural gas deliveries, claims of force majeure, and/or termination of natural gas sales contracts, resulting in a reduction in our revenues;
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations;
- lack of availability of drilling rig, 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 unrest 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.

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

- pipeline ruptures and spills;
- fires, explosions, blowouts and well cratering;
- equipment malfunctions and/or mechanical failure on high-volume, high-impact wells;
- malfunctions and/or mechanical failure at terminals or other onshore delivery points;
- 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 rail car or train derailments;
- formations with abnormal pressures and basin subsidence which could result in leakage or loss of access to hydrocarbons;
- release of pollutants;
- spills, leaks or discharges of fluids used in or produced in the course of operations, especially those that reach surface water or groundwater; and
- security breaches, cyber attacks, piracy or terroristic acts.

Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, 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, cyclones, windstorms, or "superstorms" which could affect our operations in areas such as Texas, deepwater Gulf of Mexico, Marcellus Shale or Eastern Mediterranean;
- winter storms and snow which could affect our operations in the DJ Basin and Marcellus Shale;
- extremely high temperatures, which could affect third party gathering and processing facilities in the DJ Basin and Texas;
- severe droughts resulting in new restrictions on water usage in the DJ Basin, Marcellus Shale and Texas;
- volcanoes which could affect our operations offshore Equatorial Guinea;
- flooding, or increases in sea level, which could affect our operations in low-lying areas;
- harsh weather and rough seas offshore the Falkland Islands, which could limit certain 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.

Offshore development involves significant operational and financial risks.

We have ongoing major development projects and exploration activities in several offshore areas. In certain of these areas or at certain times, there may be limited availability of suitable drilling rigs, drilling equipment, support vessels, and qualified operating personnel. In addition, frontier areas may lack the physical and oilfield service infrastructure necessary for production and transportation. As a result, development of an offshore discovery may be a lengthy process and require substantial capital investment. Difficulty and delays in consistently obtaining drilling rigs and other equipment and services at acceptable rates may lead to project delay, increased costs, inability to meet delivery requirements, and/or inability to deliver forecasted production, which could prevent the realization of our targeted return on capital or lead to unexpected future losses.

In the event of a well control incident, containment and, potentially, cleanup activities are costly. Additionally, the resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. We do not have insurance protection against all the risks that we face. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with a number of major development projects which we are progressing to final investment decision and/or production. We depend on these projects to provide long life, 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.

For example, in new development areas, 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 may be a dry hole or result in noncommercial quantities of hydrocarbons. Projects in frontier areas may require the development of technology for development drilling or well completion and our efforts may result in a dry hole or a well that finds noncommercial quantities of hydrocarbons. Development drilling has many of the same risks as exploratory drilling, which can result in the incurrence of substantial development costs without a corresponding increase in proved reserves.

All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of oil and gas reserves. This puts a property at higher risk for future impairment if commodity prices decrease or future operating or development costs increase.

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 may not have adequate infrastructure for gathering, processing or transportation, and production may be delayed until they are constructed. This results in a decrease in current cash flows and reduces the return on our investment.

Costs of drilling, completing and operating wells are often uncertain, and cost factors can adversely affect the economic viability of a project. Even a development project that is currently economically viable can become uneconomic in the future if commodity prices decrease or operating or development costs increase, resulting in impairment charges and a negative impact on our results of operations.

Exploratory drilling may not result in the discovery of commercially productive reservoirs.

We depend on exploration success to provide growth in production and reserves and are planning to conduct certain exploratory activities in 2016. Exploratory drilling requires significant capital investment and does not always result in commercial quantities of hydrocarbons or new development projects.

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.

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:

- lower commodity price outlook;
- title problems;
- near-term lease expiration;
- decisions impacting allocation of capital;
- compliance with environmental and other governmental requirements;
- availability of market, or costs to develop infrastructure;
- increases in the cost of, or shortages or delays in the availability of, drilling rigs, equipment and qualified personnel;
- unexpected drilling conditions;
- pressure or other irregularities in formations;
- equipment failures or accidents; and
- adverse weather conditions.

In addition, companies seeking new reserves often face more difficult environments, such as oil sands, deepwater, or ultra-deepwater, and often need to develop or invest in new technologies. This environment increases cost as well as drilling risk.

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.

Due to our level of planned exploration activity, future dry hole cost associated with planned exploratory wells could be material and have a negative impact on our results of operations and cash flows.

The magnitude of our offshore Eastern Mediterranean discoveries will present financial and technical challenges for us and our partners due to the large-scale development requirements.

We have been planning development scenarios for our Leviathan and Cyprus discoveries. Due to the scale of the discoveries, realization of their full economic value depends on the ability to export.

Certain changes in Israel's fiscal, and/or regulatory regimes or energy policies occurring as a result of government policy on natural gas development and/or exports could:

- delay or reduce the profitability of our Tamar and/or Leviathan development projects;
- delay or preclude closing of project financing arrangements for us or our partners; and/or
- render future exploration and development projects uneconomic.

In addition, restrictions on resource access could have a negative impact on our business including reduction of future growth rates, profitability and cash flows.

In December 2015, the Israeli Prime Minister, acting under authority of the Minister of Economy, implemented the Natural Gas Framework through execution of Section 52 of the Restrictive Trade Practices Act. Execution of Section 52 resolves and provides exemption from allegations of the Antitrust Authority with respect to the Leviathan Joint Venture partners' acquisition of petroleum rights in the underlying permits. The Israel Supreme Court held two hearings in February 2016 to consider legal challenges to the Government of Israel’s enactment of Section 52 of the Restrictive Trade Practices Act and the Court’s ruling is pending. The Court requested a response whether the government will be willing to consider enacting legislation that will support the stability provisions of the Framework. We cannot predict what will be the response from the Government of Israel nor determine the outcome of these hearings.

Finally, we have been engaged in project financing discussions. However, failure to obtain project financing on terms acceptable to us could result in a delay in these development projects.

Failure to execute successful development scenarios for Leviathan and Aphrodite could reduce our future growth and have negative effects on our operating results.

See Items 1. and 2. Business and Properties – Update on Israel - Israel Natural Gas Framework.

Failure of our partners to fund their share of development costs or obtain project financing could result in delay or cancellation of future projects, thus limiting our growth and future cash flows.

Some of our major development projects entail significant capital expenditures and have long development cycle times. For example, our joint venture arrangement with CONSOL provides for the long-term development of our Marcellus Shale acreage. In the Eastern Mediterranean, each of our natural gas development options would require a multi-billion dollar investment and span multiple years from project sanction to production.

As a result, our partners must be able to fund their share of investment costs through the development cycle, through cash flow from operations, external credit facilities, or other sources, including project financing arrangements. Factors which could reduce our partners' available cash flows or impair their ability to obtain adequate financing include, among others:

- declines in commodity prices, which reduce revenues and available cash flows;
- changes in fiscal regimes impacting royalties, taxes, fees, resource access, or level of government participation in projects;
- delay in government project approval, or other regulatory actions, which could have a negative impact on the ability to obtain financing;
- downgrades in credit rating or liquidity problems;
- increased banking regulation which could reduce access to sources of funding or make funding more expensive; and
- regional conflict, which could result in capital market reassessment of risk and withdrawal of capital.

If these issues occurred and impacted our project partners, it could result in a delay or cancellation of a project, resulting in a reduction of our reserves and production, negatively impacting the timing and receipt of planned cash flows and expected profitability.

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 enacted or promulgated by countries pursuant to the 1997 Organisation for Economic Cooperation and Development Anti-Bribery Convention 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 UK Bribery Act of 2010 is broader in scope than the FCPA and applies to public and private sector corruption and contains no facilitating payments exception.

The import/export of equipment and supplies necessary for oil and gas exploration and development activities, as well as the export of crude oil, natural gas, and liquids 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.

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.

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. Violations of environmental laws and regulations could result in fines or required mitigation activities.

For example, in April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream oil and natural gas operations within the DJ Non-Attainment Area of the DJ Basin. Compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries. See Item 8. Financial Statements and Supplementary Data - Note 18. Commitments and Contingencies.

In addition, in certain areas, legal enforcement may be impacted by significant new incentives for whistleblowers. Violations of any laws or regulations caused by either failure of our internal controls related to regulatory compliance or failure of our employees to comply with our internal policies could result in substantial civil or criminal fines, sanctions, or loss of our license to operate. In addition, as we continue to farm-in to exploration opportunities with new partners in new geographical locations, the risk of actual or alleged violation increases. Actual or alleged violations of US and international laws could damage our reputation, be expensive to defend, and impair our ability to do business.

We face various risks associated with global populism.

Globally, certain individuals and organizations are attempting to focus public attention on income and wealth distribution and corporate taxation levels, and implement income and wealth redistribution policies. These efforts, if they gain political traction, could result in increased taxation on individuals and/or corporations, as well as, potentially, increased regulation on companies and financial institutions. These measures would further burden companies and individuals with additional taxes and regulatory compliance requirements which could ultimately result in slower global economic growth and lower energy demand and possibly result in lower commodity prices. Our need to incur costs associated with responding to these developments or complying with any resulting new legal or regulatory requirements, as well as any potential increased tax expense, could 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.

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

As new technologies have been applied to our industry, we have seen significant growth in non-OPEC crude oil and natural gas supply in recent years, particularly in the US. With this expansion of oil and gas development activity, opposition toward oil and gas drilling and development activity has been growing both in the US and globally. Companies in the oil and gas industry, such as us, can be the target of opposition to development from certain stakeholder groups, including national and local governments and regulatory agencies. These anti-development efforts could be focused on limiting hydrocarbon development; reducing access to national and state government lands; delaying or canceling certain projects such as offshore drilling, shale development, and pipeline construction (including the rejection of the Keystone XL pipeline); limiting or banning the use of hydraulic fracturing; blocking activity in certain areas such as the Arctic; denying air-quality permits for drilling; and advocating for increased regulations on shale drilling and hydraulic fracturing.

In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- restrictions on the transportation of oil and gas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- targeted activist shareholder campaigns;
- increased regulation of our business;
- damaging publicity about the Company;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Our need to incur costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

We depend 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 vendors, 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, 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, also has 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. 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;
- 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 vendor or service provider could result in supply chain disruptions which could delay or halt
- of our major development projects, 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 could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions 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, including globally incorporating a risk-based cyber security framework, 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.

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

While hydraulic fracturing has been used for decades, opponents of hydraulic fracturing 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 evaluating their regulatory programs and considering additional requirements on hydraulic fracturing practices.

At the national level, bills 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 US Department of the Interior, which in March 2015 promulgated a final regulation for hydraulic fracturing on federal and Native American lands. The rule, which is being challenged in court, includes requirements related to well-bore integrity, wastewater disposal and public disclosure of chemicals. Several states and localities where we operate likewise have adopted additional restrictions on drilling activities in general or hydraulic fracturing in particular, or are considering doing so.

Additional federal, state or local restrictions on hydraulic fracturing or other drilling activities that may be imposed in areas where we conduct business, such as onshore US, could significantly increase our operating, capital and compliance costs as well as delay or halt our ability to develop crude oil, natural gas and NGL reserves. See Items 1. and 2. Business and Properties – Hydraulic Fracturing.

The marketability of our onshore US, and deepwater Gulf of Mexico production is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production from our onshore US areas and deepwater Gulf of Mexico depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, rail service, and processing facilities. We deliver crude oil, natural gas and NGLs produced from these areas through gathering systems and pipelines, the majority of which we do not own. The lack of availability of capacity on third-party systems and facilities 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. 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.

Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. 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 production, thereby harming our business and, in turn, our results of operations, cash flows, and financial condition.

Restricted land access could reduce our ability to explore for and develop crude oil, natural gas and NGL reserves.

Our ability to adequately explore for and develop crude oil and natural gas resources is affected by a number of factors related to access to land. Examples of factors which reduce our access to land include, among others:

- new municipal or state 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 land by the BLM;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, disruption of drilling, or damage to equipment;
- the presence of threatened or endangered species or of their habitat;
- disputes regarding leases; and
- disputes with landowners, royalty owners, or other operators over such matters as title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements.

Loss of access to land for which we own mineral rights could result in a reduction in our proved reserves and a negative impact on our results of operations and cash flows. Reduced ability to obtain new leases could constrain our future growth and opportunity set by limiting the expansion of our portfolio.

Our entry into new exploration ventures in areas which have no current hydrocarbon production subjects us to risks.

We hold working interests in certain areas, each of which currently has minimal or no crude oil or natural gas production, and in certain cases, limited infrastructure: offshore Cyprus, offshore the Falkland Islands, offshore Gabon and offshore Suriname. Our activities will be subject to risks including, among others:

- exploration activities in frontier areas may not result in commercially productive quantities of crude oil, natural gas and NGL reserves;
- the remote location of the Falkland Islands makes it more difficult and time-consuming to transport personnel, equipment and supplies;
- the operating environment offshore the Falkland Islands includes harsh weather and rough seas which could limit seismic surveys and other exploration activities during certain periods; and
- pandemics and epidemics, which may adversely affect our business operations through travel or other restrictions; and
- there have been numerous acts of piracy, kidnapping, civil strife, regional conflict, border disputes, cross-border violence, and war, as well as violence associated with corruption, drug trafficking and regime changes in certain areas.

These risks could be intensified if commercial quantities of oil or natural gas are discovered. We may not be able to compensate for or fully mitigate these risks.

Our ability to produce crude oil, natural gas and NGLs 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, natural gas and NGLs 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 operating cost. Waste water from oil and gas operations often is disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to increased public scrutiny of injection safety.

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 operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition. See Items 1. and 2. Business and Properties – Hydraulic Fracturing.

Indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2015, we had $8.0 billion of debt, of which $53 million is due within 12 months. Our indebtedness represented 43% of our total book capitalization (sum of debt plus shareholders' equity) at December 31, 2015.

Our 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) will 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 in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and/or availability of future financing, and lower ratings will increase the interest rate and fees we pay on our unsecured revolving credit facility (Credit Facility); 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 our debt depends on future performance. General economic conditions, crude oil, natural gas, and NGL prices, and financial, business and other factors will 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. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

A downgrade or other negative action with respect to our credit rating could negatively impact our business and financial condition.

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, and potentially subject us to additional bonding and other assurance requirements with respect to our deepwater Gulf of Mexico development plans. A lowering of our credit rating may negatively affect the cost, terms, conditions and availability of future financing.

Deterioration of global economic growth or business or industry conditions may impede our ability to access capital markets or materially adversely impact our operating results and financial position.

The recovery from the global financial crisis of 2008 and resulting recession has been slow and uneven. Market volatility and slowing consumer demand have increased economic uncertainty, and the current global economic growth rate is slower than what was experienced in the decade preceding the crisis. Many developed countries are constrained by long-term structural government budget deficits. The need for government fiscal reform is offset against populist calls for additional government social spending and regulation as a result of slow or negligible economic growth.

As we enter 2016, slower Chinese gross domestic product growth and emerging market debt levels present near-term challenges to the global economy and overall demand for energy. Global economic growth drives demand for energy from all sources, including hydrocarbons. With current global economic growth slowing, demand growth for crude oil, natural gas and NGL production has, in turn, softened. A decrease in demand, notwithstanding impacts from other factors, could result in lower commodity prices, which would reduce our cash flows from operations, our profitability and our liquidity and financial position.

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:

- large multi-national, integrated oil companies;
- state-controlled national oil companies;
- US independent oil and gas companies;
- service companies engaging in exploration and production activities; and
- private oil and gas equity funds.

We face competition in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our crude oil, natural gas and NGL production;
- seeking to acquire 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.

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

There are numerous uncertainties inherent in estimating crude oil, natural gas and NGL reserves and their value, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner. In accordance with the SEC's rules for oil and gas reserves reporting, our reserves estimates are based on 12-month average prices; therefore, reserves quantities will change when actual prices increase or decrease. The 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;
- the assumed effects of regulations by governmental agencies, including the SEC;
- assumptions concerning future crude oil, natural gas, and NGL prices;
- anticipated development cycle time;
- future development costs;
- future operating 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, natural gas and NGLs 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, natural gas and NGL 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.

Additionally, because some of our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis 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. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves 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, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. For example, in the state of Louisiana, 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. If we are not able to successfully defend ourselves, there could be a delay or even 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. Legal proceedings could result in a 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.

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, our 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, FPSO and underwater pipelines for export of natural gas from Leviathan will require a multi-billion dollar investment prior to production startup, and our CONSOL Carried Cost Obligation requires us to pay one-third of CONSOL's working interest share of certain drilling and completion costs in periods where the average Henry Hub natural gas prices equals or exceeds $4.00 per MMBtu. Furthermore, while the majority of our assets are held by production, certain of our assets, such as our Eagle Ford Shale and Permian Basin properties, are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas and failure to meet these obligations may result in the loss of a lease.

Historically, we have funded our capital expenditures through a combination of cash flows from operations, our Credit Facility, debt and equity issuances, and occasional sales of non-strategic assets. Future cash flows from operations are subject to a number of variables, such as the level of production from existing wells, prices of crude oil, natural gas and NGLs, and our success in finding, developing and producing new reserves.

For 2016, we have designed a substantially-reduced capital investment program to address the current commodity price level and forward strip prices. If commodity prices decline further, we will likely further reduce the 2016 capital 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 compared to prior years. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook 2016 – Capital Investment Program.

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 trade, joint venture, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. In addition, we are the operator on a majority of our large joint venture development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs. For example, our partners in the Eastern Mediterranean must obtain financing for their share of significant development expenditures at Leviathan and offshore Cyprus.

In addition, some of our purchasers and joint venture partners are not as creditworthy as we are and may experience credit downgrades or liquidity problems that may hinder their ability to obtain financing. Counterparty liquidity problems could result in a delay in our receiving proceeds from commodity sales or reimbursement of joint venture costs. Nonperformance by a trade creditor or joint venture partner could result in significant financial losses.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. During periods of falling commodity prices, our commodity derivative receivable positions increase, which increases our counterparty credit exposure. We also had approximately $1.0 billion in cash and cash equivalents at December 31, 2015 deposited with financial institutions, a majority of which was invested in money market funds and short-term deposits with major financial institutions. While we monitor the creditworthiness of the banks and financial institutions with which we invest and engage in hedging transactions, we are unable to predict sudden changes in solvency of our financial institutions and may be exposed to associated risks.

If one or more of our trade creditors, joint venture partners, hedge counterparties and financial institutions were to experience a sudden deterioration in liquidity, it could impair their ability to perform under the terms of our contracts. We are unable to predict sudden changes in creditworthiness or ability of these parties to perform and could incur significant financial losses.

Commodity, interest rate and exchange rate hedging transactions may limit our potential gains.

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 crude oil and natural gas price 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 crude oil and natural gas prices rise over the price established by the arrangements.

Global commodity prices are volatile. Such volatility challenges our ability to forecast and, as a result, it may become more difficult to manage our hedging program. In trying to manage our exposure to commodity price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. Hedging transactions may also expose us to the risk of financial loss in certain circumstances, including instances in which: our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; the counterparties to our futures contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices.

In addition, our hedging program may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. We are unlikely to hedge future revenues at the same level as our existing hedging arrangements in the current commodity price environment. As such, our revenues will be more susceptible to commodity price volatility as our commodity price derivatives settle and are not replaced.

We may use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. Interest rates are variable and we may also end up hedging too much or too little when we attempt to effectively fix cash flows related to interest payments on an anticipated debt issuance.

We have significant international operations and may enter into foreign currency derivative instruments in the future. Currency exchange rates are variable and we may also end up hedging too much or too little when we attempt to mitigate our foreign currency exchange risk.

Our hedging transactions may not reduce the risk or minimize the effect of volatility in crude oil or natural gas prices, interest rates, or exchange rates. See Item 8. Financial Statements and Supplementary Data – Note 8. 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.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters or other catastrophic events such as blowouts, well cratering, fire and explosion and loss of well control which can result in damage to or destruction of wells 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 political developments such as terrorist acts, piracy, civil disturbances, war, and expropriation or nationalization of assets, which can cause loss of or damage to our property.

Our insurance program 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 such events as hurricanes, earthquakes, tsunami 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 the Gulf of Mexico and other 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 offshore 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 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 Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Risk and Insurance Program*.

We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.

Our business is subject to 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, natural gas and NGLs. From time to time, in varying degrees, political developments and international, federal, state and local laws affect our operations. Changes in price controls, taxes and environmental laws relating to the crude oil and natural gas industry have the ability to substantially affect crude oil, natural gas and NGL production, operations and economics. 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.

Some of the complex laws and regulations our industry is subject to include the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Safe Drinking Water Act, and the Occupational Safety and Health Act. Environmental laws, in particular, can change frequently, often become stricter and at times may force us to incur additional costs as changes are implemented. In 2015, for example, US EPA lowered the ambient air standard for ozone, which eventually may result in more stringent emission controls for our operations, and released a final rule jointly with the US Army Corps of Engineers that may expand federal jurisdiction over streams and wetlands, while the Department of the Interior proposed more stringent design requirements and operational procedures for critical well control equipment used in offshore oil and gas operations.

Additionally, the unintentional 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 costs to achieve remediation objectives and/or requirements.

In April 2015, for example, we entered into a Consent Decree with the US EPA, US Department of Justice and State of Colorado to improve emission control systems at a number of our condensate storage tanks within the DJ Basin. The Consent Decree required us to pay a civil penalty and to perform certain injunctive relief activities, mitigation projects, and supplemental environmental projects. We will incur costs associated with these activities. In addition, compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries within the Non-Attainment Area of the DJ Basin.

Noncompliance with existing or future legislation or regulations could potentially result in an increased risk of civil or criminal fines or sanctions. For example, fines or sanctions associated with a well incident or spill could well exceed the actual cost of containment and cleanup.

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

- increase the costs of drilling exploratory and development wells;
- cause delays in, or preclude, the development of our projects resulting in longer development cycle times;
- result in additional operating and capital costs;
- 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 may result in a reduction of our cash flows, profitability, and 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.

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

Climate and related energy policy, laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential developments that could impact the sources and uses of energy. In December 2015, the United States and 194 other participating countries adopted the Paris Agreement, which calls for each participating country to establish their own nationally determined standards for reducing carbon output. The Paris Agreement is intended to succeed the Kyoto Protocol and must be ratified by the 55 countries that produce 55% of the world's GHGs before it becomes fully effective. Towards that end, the United States intends to achieve an economy-wide target of reducing its GHG emissions by 26-28% less than the 2005 level in 2025 and to use best efforts to reach a 28% reduction. To obtain those reductions, US EPA has been proposing and issuing various rules, including a 2015 proposal to control methane air emissions from oil and gas sources. Many states also are pursuing climate requirements either directly or indirectly through such measures as alternative fuel mandates. These measures may reduce the future demand for our products, particularly crude oil. On the other hand, GHG emissions regulations may increase the demand for natural gas, especially as a fuel for power generation.

We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are impacted in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in climate and energy policies. Finally, if those policies are not effective, increasing concentrations of GHGs may result in higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic effects. If any such effects were to occur, they could have a material adverse effect on our business, financial condition and results of operations.

The unavailability or high cost of drilling rigs, equipment, supplies, other oil field services and personnel 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, from time to time, there is a shortage of drilling rigs, equipment, supplies and oilfield services. There may also be a shortage of trained and experienced personnel. During these periods, the costs of such items are substantially greater and their availability may be limited, particularly in areas of high activity and demand and in some international locations that typically have limited availability of equipment and personnel.

Regulatory changes, such as those related to hydraulic fracturing, and recent consolidations of oil field service companies, may also result in reduced availability and/or higher costs. As a result, drilling rigs and oilfield services may not be available at rates that provide a satisfactory return on our investment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Contractual Obligations*.

Provisions in our Certificate of Incorporation and Delaware law may inhibit a takeover of us.

Under our Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our shareholders. Issuance of these shares could make it more difficult to acquire us without the approval of our Board of Directors as more shares would have to be acquired to gain control. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our shareholders.

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 ability to successfully and economically explore for and develop crude oil, natural gas and NGL resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration, development, and acquisition activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions;
- the impact of governmental fiscal terms and/or regulation, such as that involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon 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.

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 18. 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 will be 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.

Stock Prices and Dividends by Quarters The high and low sales price per share of our common stock on the NYSE and quarterly dividends paid per share were as follows:

	High	Low	Dividends Per Share
2014			
First Quarter	$ 71.98	$ 60.14	$ 0.14
Second Quarter	79.63	68.83	0.18
Third Quarter	77.93	65.67	0.18
Fourth Quarter	68.73	42.11	0.18
2015			
First Quarter	$ 52.42	$ 41.01	$ 0.18
Second Quarter	53.68	42.13	0.18
Third Quarter	43.03	29.13	0.18
Fourth Quarter	39.85	29.56	0.18

On January 26, 2016, the Board of Directors declared a quarterly cash dividend of $0.10 per common share, which represents a reduction of $0.08 from fourth quarter 2015, and aligns the dividend yield with historical levels. The dividend will be paid February 22, 2016, to shareholders of record on February 8, 2016. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Transfer Agent and Registrar The transfer agent and registrar for our common stock is Wells Fargo Bank, N.A., 1110 Centre Pointe Curve, Suite 101 Mendota Heights, MN 55120.

Stockholders' Profile Pursuant to the records of the transfer agent, as of January 15, 2016, the number of holders of record of our common stock was 595.

Stock Repurchases The following table summarizes repurchases of our common stock occurring in fourth quarter 2015.

Period	Total Number of Shares Purchased [(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
10/1/2015 - 10/31/2015	3,099	$ 34.25	—	—
11/1/2015 - 11/30/2015	4,983	37.63	—	—
12/1/2015 - 12/31/2015	1,433	33.90	—	—
Total	9,515	$ 35.97	—	—

(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares of restricted stock issued under our stock-based compensation plans.

Equity Compensation Plan Information The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2015:

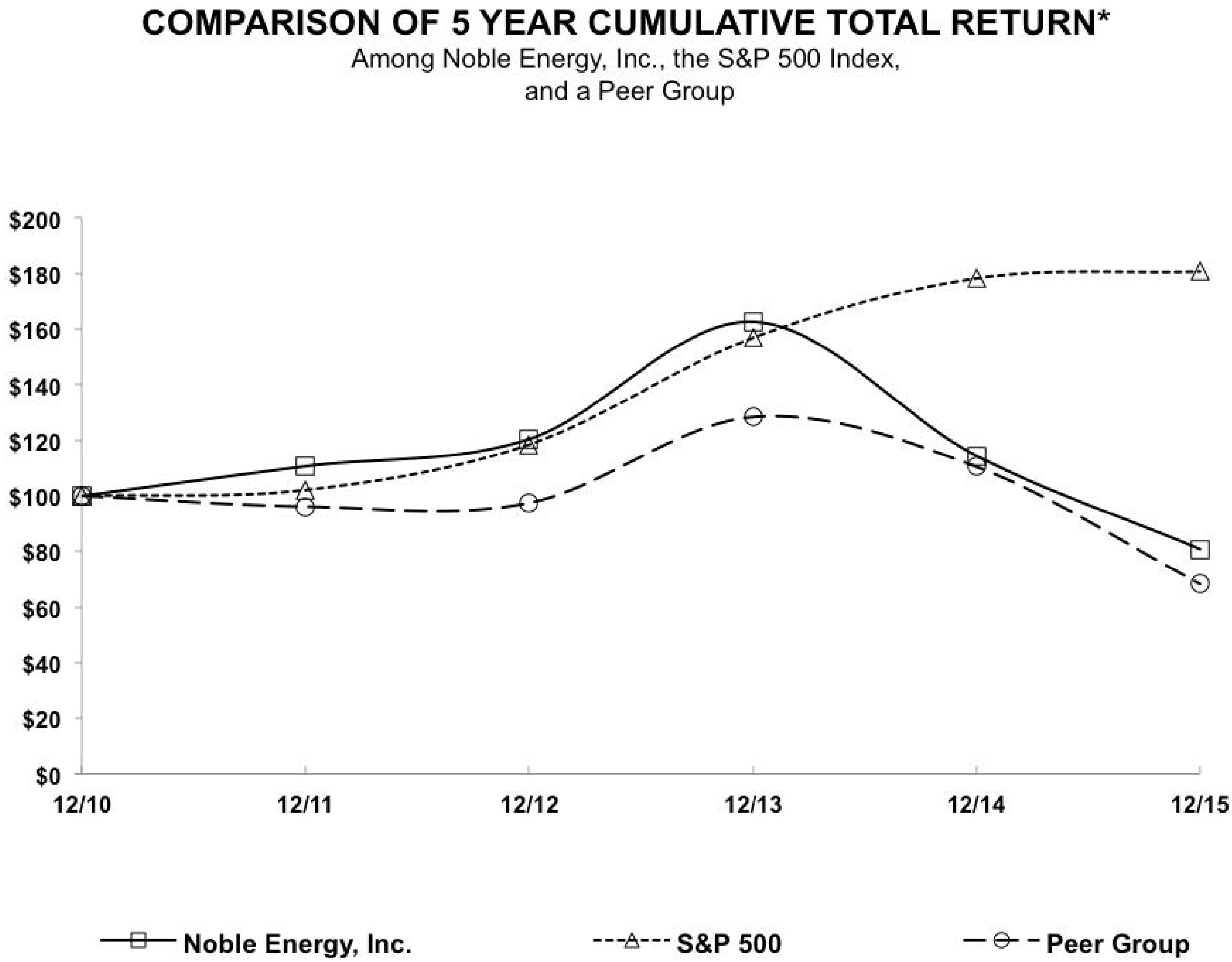
Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity Compensation Plans Approved by Security Holders	14,571,012	$ 44.59	16,713,215
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	14,571,012	$ 44.59	16,713,215

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2010 to December 31, 2015. 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.

The companies in our peer group consist of the following:

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

The comparison assumes $100 was invested on December 31, 2010 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.



Year Ended December 31,	2010	2011	2012	2013	2014	2015
Noble Energy, Inc.	$ 100.00	$ 110.64	$ 120.40	$ 162.63	$ 114.45	$ 80.87
S&P 500	100.00	102.11	118.45	156.82	178.29	180.75
Peer Group	100.00	96.16	97.45	128.36	110.46	68.34

Item 6. Selected Financial Data

(millions, except as noted)	Year Ended December 31, 2015	2014	2013	2012	2011
Revenues and Income					
Total Revenues	$ 3,133	$ 5,101	$ 5,015	$ 4,223	$ 3,404
Income (Loss) from Continuing Operations	(2,441)	1,214	907	965	412
Net Income (Loss)	(2,441)	1,214	978	1,027	453
Per Share Data [1]					
Earnings (Loss) Per Share - Basic					
Income (Loss) from Continuing Operations	$ (6.07)	$ 3.36	$ 2.53	$ 2.71	$ 1.17
Net Income (Loss)	(6.07)	3.36	2.72	2.89	1.28
Earnings (Loss) Per Share - Diluted					
Income (Loss) from Continuing Operations	(6.07)	3.27	2.50	2.68	1.15
Net Income (Loss)	(6.07)	3.27	2.69	2.86	1.27
Cash Dividends Per Share	0.72	0.68	0.55	0.45	0.40
Year-End Stock Price Per Share	32.93	47.43	68.11	50.87	47.20
Weighted Average Shares Outstanding					
Basic	402	361	359	356	353
Diluted	402	367	363	359	357
Cash Flows					
Net Cash Provided by Operating Activities	$ 2,062	$ 3,506	$ 2,937	$ 2,933	$ 2,170
Additions to Property, Plant and Equipment	2,979	4,871	3,947	3,650	2,594
Acquisitions [2]	61	—	—	—	527
Proceeds from Divestitures	151	321	327	1,160	77
Financial Position					
Cash and Cash Equivalents	$ 1,028	$ 1,183	$ 1,117	$ 1,387	$ 1,455
Property, Plant, and Equipment, Net	21,300	18,143	15,725	13,551	12,782
Goodwill [3]	—	620	627	635	696
Total Assets	24,196	22,518	19,642	17,554	16,444
Long-term Obligations					
Long-Term Debt	7,976	6,068	4,566	3,736	4,100
Deferred Income Taxes	2,826	2,516	2,441	2,218	2,059
Asset Retirement Obligations	861	670	547	333	344
Other	358	417	562	477	408
Shareholders' Equity	10,370	10,325	9,184	8,258	7,265
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	112	103	99	86	56
Average Realized Price ($/Bbl)	$ 45.00	$ 91.58	$ 100.29	$ 101.52	$ 99.17
Consolidated Natural Gas Sales (MMcf/d)	1,187	992	901	774	806
Average Realized Price ($/Mcf)	$ 2.44	$ 3.38	$ 2.97	$ 2.19	$ 3.00
Consolidated NGL Sales (MBbl/d)	39	23	16	16	15
Average Realized Price ($/Bbl)	$ 10.39	$ 32.04	$ 35.53	$ 35.36	$ 48.35
Proved Reserves					
Crude Oil and Condensate Reserves (MMBbls)	307	304	322	268	277
Natural Gas Reserves (Bcf)	5,549	5,833	5,828	4,964	5,043
NGL Reserves (MMBbls)	189	128	113	89	92
Total Reserves (MMBoe)	1,421	1,404	1,406	1,184	1,209
Number of Employees	2,395	2,735	2,527	2,190	1,876

(1) Amounts adjusted for the 2-for-1 stock split which occurred during second quarter 2013.
(2) 2015 includes $61 million cash received in the Rosetta Merger, an all-stock transaction.
(3) Goodwill was fully impaired at December 31, 2015. See Item 8. Financial Statements and Supplementary Data – Note 4. Goodwill.

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. We use common industry terms, such as thousand barrels of oil equivalent per day (MBoe/d) and million cubic feet equivalent per day (MMcfe/d), to discuss production and sales volumes. Our MD&A is presented in the following major sections:

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

EXECUTIVE OVERVIEW

Strategy We are a globally diversified explorer and producer of crude oil, natural gas and NGLs. We aim to achieve sustainable growth in value and cash flow through exploration success and the development of a high-quality and diverse, worldwide portfolio of assets with investment flexibility between onshore unconventional developments and offshore organic exploration leading to major development projects. Our portfolio is further diversified through US and international projects and production mix among crude oil, natural gas, and NGLs. Our legacy core operating areas include the DJ Basin and Marcellus Shale (onshore US), deepwater Gulf of Mexico, offshore West Africa, and offshore Eastern Mediterranean, where we have strategic competitive advantage and which we believe generate attractive returns over the oil and gas business cycle.

In third quarter 2015, we added two new core operating areas, the Eagle Ford Shale and the Permian Basin, as a result of our merger with Rosetta. We also seek to enter other potential new core areas and are conducting exploration activities in locations such as the Falkland Islands, Cameroon, Suriname and Gabon. We may also conclude that an exploration area is not commercially viable and, therefore, may exit locations, such as we did in 2015 with Nevada, Sierra Leone and Nicaragua.

Impact of Current Commodity Prices The upstream oil and gas business is cyclical and we are currently operating in a sustained lower commodity price environment. Our consolidated average realized prices for fiscal year 2015 decreased 51% for crude oil, 28% for natural gas and 68% for NGLs as compared with 2014. These low prices resulted in a reduction in our capital spending program, had significant negative impacts on our revenues, profitability, cash flows and proved reserves, resulted in asset and goodwill impairments, caused us to execute certain organizational changes, and led to reductions in our stock price.

Thus far in 2016, commodity prices have continued to trade in a low range, with crude oil prices falling below $30.00 per barrel on some occasions. If the industry downturn continues for an extended period, or becomes more severe, we could experience additional material negative impacts on our revenues, profitability, cash flows, liquidity, and reserves, and we could consider further reductions in our capital program or dividends, asset sales or additional organizational changes. Our production and our stock price could decline further as a result of these activities. See Item 1A. Risk Factors – *We are currently experiencing a severe downturn in the oil and gas business cycle, and an extended or more severe downturn could have material adverse effects on our results of operations, our liquidity, and the price of our common stock.*

2015 Achievements Despite operating in a low commodity price environment, there were numerous operational successes in 2015. Just as importantly, we positioned ourselves for long-term operational performance and future growth in the current commodity price environment. We achieved material reductions in capital and controllable unit costs, supporting project returns and margin improvements, while delivering year-over-year volume growth. In addition, we took numerous steps to enhance our liquidity position. In summary, we exited 2015 with operational momentum, investment flexibility, and strong financial liquidity which we expect to carry over to 2016.

Our successes included the following:

Onshore US Growth Onshore, we continued our DJ Basin development activity and, in third quarter, added two new onshore US core areas through the Rosetta Merger in an all-stock transaction. By the end of 2015, we had fully integrated Rosetta's operations. In addition, by leveraging our expertise in other premier US onshore basins, we have begun to realize significant operational synergies positively impacting our drilling and production activities.

Production Volume Increases Efficiencies generated by drilling time reductions and completion improvements resulted in increased production as we delivered year-over-year volume growth of almost 20% (10% excluding the impact of the Rosetta Merger) resulting in record average sales volumes of 355 MBoe/d.

Capital Cost Reductions While delivering higher production volumes, we realized significant reductions in capital expenditures, over 40% from 2014.

Lease Operating and G&A Expense Reductions We realized significant reductions in unit costs for lease operating and general and administrative (G&A) expenses, 21% and 34%, respectively, on a BOE basis.

Major Projects Advancement Offshore, our major project execution capabilities enabled us to deliver two new major projects and progress on a third in the Gulf of Mexico. Our operated projects in West Africa and Israel continued to provide world-class reliability and, in Israel, we achieved substantial progress on the government framework for crude oil and natural gas resource development.

Liquidity Enhancements We ensured liquidity by accessing the capital markets with a common stock offering and extending our Credit Facility maturity date by two years. More recently, we generated over $190 million of cash from the close of our Cyprus farmout and sale of Karish and Tanin discoveries, and undertook debt refinancing activities to enhance our financial flexibility.

Positioned for the Future We believe the following factors will contribute to the sustainability of our business in a lower commodity price environment:

- we have a high-quality, globally diversified portfolio of assets, the majority of which are held by production and provide investment flexibility;
- we have achieved sustainable cost reductions (and are well-positioned on the US supply curve) impacting both operating expenses and capital items, positively impacting operating cash flows;
- we are focused on operational efficiencies and projects that can be profitable in the current commodity price environment;
- we have designed a substantially-reduced capital investment program, with flexibility allowing us to respond to changing commodity price conditions in 2016;
- we plan to defer certain activities to protect our strong liquidity position and expect the capital investment program to be more closely aligned with cash flow;
- we have established a commodity price hedging program for 2016; and
- we have robust liquidity of $5.0 billion at December 31, 2015 and ability to access capital markets.

See also Operating Outlook, Results of Operations, and Liquidity and Capital Resources, below.

2015 Financial Results Our financial results, some of which were significantly impacted by declining crude oil and natural gas prices, included:

- net loss of $2.4 billion, as compared with net income of $1.2 billion for 2014;
- net gain on commodity derivative instruments of $501 million (including $508 million non-cash loss), as compared with $976 million net gain (including $947 million non-cash gain) for 2014;
- dry hole expense of $266 million, as compared with $226 million for 2014;
- reduced lease operating expense of $4.43 per BOE, as compared with $5.58 per BOE for 2014, a reduction of 21%;
- reduced general and administrative expense of $3.11 per BOE, as compared with $4.73 per BOE for 2014, a reduction of 34%;
- asset impairment charges of $533 million, as compared with $500 million for 2014;
- goodwill impairment charge of $779 million;
- diluted loss per share of $6.07, as compared with diluted earnings per share of $3.27 for 2014;
- cash flows provided by operating activities of $2.1 billion, as compared with $3.5 billion in 2014; and
- capital expenditures, excluding Rosetta Merger, of $2.9 billion, as compared with $5.0 billion in 2014.

Significant Events Impacting Liquidity Included:

- net cash proceeds of $1.1 billion received from public offering of shares of common stock;
- extension of Credit Facility maturity date to August 27, 2020; and
- cash dividend repatriation of $858 million from foreign operations.

Year-end Financial Metrics Included:

- cash balance of $1.0 billion, as compared with $1.2 billion at December 31, 2014;
- total liquidity of $5.0 billion, as compared with $5.2 billion at December 31, 2014; and
- ratio of debt-to-book capital of 43%, as compared with 38% at December 31, 2014.

Cost Reduction Efforts During 2015, we focused on maintaining our strong safety culture, driving operational efficiencies and reducing our cost structure. Cost reduction initiatives, including both operational enhancements and new pricing arrangements with suppliers, resulted in significantly reduced unit costs in lease operating expense and general and administrative expense as compared with 2014. Our global portfolio provides significant optionality, allowing us to reduce our capital spending, excluding the Rosetta Merger, by 42% for 2015, as compared with 2014. This capital spending reduction, coupled with cost reduction activities, has aligned overall cash expenditures more closely with operating cash flows in the current commodity price environment. We also implemented organizational changes including relocating our Ardmore, Oklahoma office, reducing our total workforce and consolidating our Houston personnel to our corporate headquarters in Houston.

Sales Volumes On a BOE basis, total consolidated sales volumes were 20% higher for 2015 as compared with 2014, and our mix of sales volumes was 43% global liquids, 23% international natural gas, and 34% US natural gas. On a BOE basis and excluding the impact of the Rosetta Merger, total sales volumes were 10% higher for 2015 as compared with 2014, and our mix of sales volumes was 41% global liquids, 25% international natural gas, and 34% US natural gas. See Results of Operations – Revenues, below.

Merger, Acquisitions and Divestitures During 2015, activity included the following:

- completion of the Rosetta Merger;
- acquisition of a non-operated 20% working interest in Block 54 offshore Suriname;
- sale of certain non-core onshore US properties, generating net proceeds of $151 million;
- farm-out of a portion of our interest in Block 12 offshore Cyprus for total consideration of $165 million, $125 million of which was received in January 2016; and
- sale of our 47% interest in the Alon A and Alon C licenses offshore Israel, which include Karish and Tanin natural gas discoveries, for total transaction value of $73 million ($67 million for asset consideration and $6 million from adjustment of costs), which closed in January 2016.

See Item 8. Financial Statements and Supplementary Data – Note 3. Merger, Acquisitions and Divestitures.

Commodity Hedging Activities To enhance the predictability of our cash flows and support our capital investment program, we have historically hedged portions of our expected global crude oil and domestic natural gas revenues. In the current crude oil price environment, our hedges for 2016 revenues are expected to contribute to cash flows from operations, offsetting a portion of declines in revenues. Our 2016 hedges cover approximately 35% of our expected global crude oil and 25% of our expected US natural gas production.

We use mark-to-market accounting for our commodity derivative instruments and recognize all gains and losses on such instruments in earnings in the period in which they occur. Derivative gains and losses included in net income include both cash settlements during the period and non-cash gains or losses due to the change in the mark-to-market value. The use of mark-to-market accounting adds volatility to our net income. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Update on Israel Antitrust Matters During 2015, the Israeli government implemented the Natural Gas Framework to support development of offshore natural gas reserves and natural gas exports. See Items 1. and 2. Business and Properties – Update on Israel - Israel Natural Gas Framework.

Goodwill Impairment Prior to conducting our goodwill impairment test, our consolidated balance sheet included $779 million of goodwill, all of which was attributable to the US reporting unit. This goodwill related primarily to the excess purchase price over amounts assigned to assets and liabilities from the Rosetta Merger in 2015 of $163 million and the Patina Merger in 2005. Primarily due to the current commodity price environment, we determined that our goodwill balance was not recoverable and fully impaired it, recording goodwill impairment charges of $779 million during fourth quarter 2015. See Item 8. Financial Statements and Supplementary Data – Note 4. Goodwill.

Asset Impairment As an oil and gas company, we have capitalized costs associated with activities along the entire range of the oil and gas investment cycle. These investments are included in property, plant and equipment in our consolidated balance sheet and consist primarily of acquisition costs, capitalized exploratory well costs and development costs. In line with applicable accounting conventions, we periodically evaluate our investments for impairment whenever events or circumstances indicate that the recorded carrying values of the assets may not be recoverable. We use forward-looking models that include various assumptions, such as anticipated exploration activities, economic evaluation of exploratory wells and future cash flows, and apply the model that is most closely aligned with the maturity of the asset along the investment cycle.

We recorded total property impairment charges of $533 million in 2015, including $490 million during fourth quarter 2015. Declines in crude oil prices triggered $481 million of the total impairment charges, which were related to certain deepwater Gulf of Mexico, Eastern Mediterranean and Equatorial Guinea properties. See Critical Accounting Policies – Impairment of Proved Oil and Gas Properties and Other Investments and Impairment of Unproved Oil and Gas Properties, below, and Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

OPERATING OUTLOOK

2016 Outlook

Crude Oil The oil and gas industry is cyclical and commodity prices are volatile. Three key drivers of global crude oil prices are: OPEC crude oil supply, non-OPEC crude oil supply and global crude oil demand. During 2014, crude oil became oversupplied as production from non-OPEC producers increased, primarily driven by US crude oil production growth from tight formations and the de-bottlenecking of transportation infrastructure, while global crude oil demand growth was muted on lower global economic growth especially in Europe, coupled with slower growth in China.

Crude oil futures prices began softening in third quarter 2014, and fell rapidly in November 2014, following OPEC's decision not to reduce production quotas. During 2015, prices fell to multi-year lows and the lowest levels since the 2008 financial crisis. Thus far, there has been no price recovery in 2016, prices have fallen to new lows and NYMEX crude oil futures continue to be weak.

The outlook for crude oil prices during 2016 depends primarily on supply and demand dynamics and global security concerns in crude oil-producing nations. Production levels will be a primary determinant for 2016. If, during 2016, OPEC maintains its position against cutting production, we expect prices to be low or move lower. In addition, record crude oil inventories exert downward pressure on prices. On the demand side, recent projections have reduced anticipated global crude oil demand growth for 2016 and Chinese economic indicators continue to soften which supports the current oversupply situation and a soft pricing environment.

Longer term, we expect supply and demand to re-balance. If prices remain at lower levels, we expect producers will reduce investment which will, over time, reduce production, helping to balance supply and demand in the crude oil market.

Natural Gas The US domestic natural gas market continues to be oversupplied. During 2015, prices remained weak, falling to multi-year lows. In addition, location differentials increased in some regions, such as the Marcellus Shale, resulting in further declines in natural gas prices. Infrastructure projects are in place to move natural gas out of the Marcellus Shale which should improve differentials in the future. Domestic production has continued to grow, due to drilling efficiency and a backlog of drilled but uncompleted wells that came online with completion of new pipeline infrastructure in 2015, which outstripped demand growth.

Although the pace of drilling has slowed, it is possible that there may not be much improvement in the domestic natural gas supply and demand balance and that oversupply will persist, which could lead to continued price softness in 2016. At a minimum, we expect US natural gas prices to continue to trade in a low range for the near term.

Because the global economic outlook and commodity price environment are uncertain, we have built a strong liquidity position to ensure financial flexibility. We have also planned a substantially reduced 2016 capital investment program that will be responsive to conditions that develop in 2016. This program, coupled with our commodity hedging programs, will support continued investment in a volatile commodity price environment. See 2016 Capital Investment Program, below.

2016 Production We have adopted a comprehensive effort to spend within cash flow, manage the Company's balance sheet and position ourselves for future growth. To this end, we plan to defer certain activities to protect our liquidity position and adopted a 2016 capital program more closely aligned with expected cash flow. Therefore, our total crude oil, natural gas and NGL production for 2016 may not grow at a rate consistent with prior years. Production may be impacted by factors including:

- commodity prices, which, if subject to further decline, could result in current production becoming uneconomic;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, will impact near-term production volumes;
- the reduced level of horizontal drilling activity onshore US and the decline in DJ Basin legacy vertical well production;
- timing of start-up of a low pressure line-loop system, performance of gathering and processing infrastructure, capacity constraints of midstream facilities serving those wells, offset by additional capacity from new facilities, and occurrence of other events which impact capacity constraints of midstream facilities serving our DJ Basin wells;
- timing of start-up of the Gunflint project (deepwater Gulf of Mexico) and Alba compression project (offshore Equatorial Guinea);
- Israeli demand for electricity, which affects demand for natural gas as fuel for power generation and industrial market growth, and which is impacted by unseasonable weather;
- conversion of Israeli electricity portfolio from coal to natural gas;
- potential for exports of natural gas to Egypt and Jordan;
- variations in West Africa crude oil and condensate sales volumes due to potential Aseng FPSO downtime and timing of liftings, and variations in natural gas sales volumes related to potential downtime at the methanol, LPG and/or LNG plants;
- natural field decline in the deepwater Gulf of Mexico and offshore Equatorial Guinea;

- overall performance from onshore US wells;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico, or winter storms and flooding impacting onshore US operations;
- reliability of support equipment and facilities and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in production and/or mid-stream processing;
- pending Alba and Alen field unitizations in West Africa;
  potential shut-in of US producing properties if storage capacity becomes unavailable;
- potential drilling and/or completion permit delays due to future regulatory changes; and
- potential purchases of producing properties or divestments of non-core operating assets.

2016 Capital Investment Program Given the current commodity price environment, we have designed a substantially reduced and flexible capital investment program that is part of our comprehensive effort to spend within cash flow and manage the Company's balance sheet.

Our preliminary 2016 capital investment program will accommodate an investment level of approximately $1.5 billion, approximately 50% lower than the 2015 program. The program allocates two-thirds of total investment to core onshore US assets and the remaining one-third to offshore development and exploration.

Specifically, the capital investment program allocates approximately $600 million to the DJ Basin, $150 million to the Marcellus Shale, $250 million to the Eagle Ford Shale and Permian Basin, $250 million to the Gulf of Mexico, and $100 million to offshore Israel, with the remainder for West Africa and other projects.

See Liquidity and Capital Resources – Financing Activities and Contractual Obligations.

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, natural gas and NGL production;
- operating and development costs and the ability to achieve material supplier price reductions;
- production, drilling, delivery commitments or other contractual obligations;
- permitting activity in the deepwater Gulf of Mexico;
- drilling results;
- CONSOL Carried Cost Obligation (See Liquidity and Capital Resources – Off-Balance Sheet Arrangements);
- property acquisitions and divestitures;
- exploration activity;
- cash flows from operations;
- indebtedness levels;
- availability of financing or other sources of funding;
- potential legislative or regulatory changes regarding the use of hydraulic fracturing;
- potential changes in the fiscal regimes of the US and other countries in which we operate; and
- impact of new laws and regulations on our business practices.

See Items 1. and 2. Business and Properties – Update on Israel – Israel Natural Gas Framework, and Liquidity and Capital Resources – Contractual Obligations – *Marcellus Joint Development Agreement, Exploration Commitments* and *Continuous Development Obligations.*

Exploration Program We continually evaluate our exploration inventory to provide additional long-term growth opportunities and potential new core areas. In addition, each of our existing core areas has remaining exploration upside, including the potential for low-cost addition of new acreage or bolt-on activity. We continue to leverage existing activities to improve our exploration programs in these core areas.

Prior to the commodity price downturn in 2014, we devoted 10% or more of our capital investment program to exploration and associated appraisal activities. Our 2016 exploration program has been reduced commensurate with overall capital reductions.

We do not always encounter hydrocarbons through our drilling activities. In addition, we may find hydrocarbons but subsequently reach a decision, through additional analysis or appraisal drilling, that a project is not economically or operationally viable.

Major Development Project Inventory Our current inventory of major development projects requires significant capital investments.

As noted above, we expect to continue to invest in our onshore US and deepwater Gulf of Mexico development projects in 2016. We plan to fund these projects from cash flows from operations, cash on hand, proceeds from divestments of non-core assets, borrowings under our Credit Facility, and/or other sources of funding. See Liquidity and Capital Resources – Capital Structure/ Financing Strategy.

As operator on the majority of our development projects, we pay gross joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs. In addition, some of our joint venture partners may not be as creditworthy as we are and may experience liquidity problems, exacerbated by low commodity prices. This could result in a delay in our receiving reimbursement of joint venture costs and increases our counterparty credit risk. See Item 1A. Risk Factors.

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

Exploration Activities We have an active exploratory drilling program. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. For example, we are currently drilling the Silvergate prospect in the deepwater Gulf of Mexico. If we conclude that the well does not encounter hydrocarbons or that this prospect is not economically viable, the costs incurred would be recorded as dry hole expense.

Total capitalized costs related to previous exploratory wells totaled $1.4 billion at December 31, 2015. If, in the future, we determine that the well has not found proved reserves or a potential project is deemed noncommercial, the related well costs would immediately be charged to exploration expense as dry hole cost. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

We may not conduct exploration activities prior to lease expirations. For example, in the deepwater Gulf of Mexico, while we continue to mature our prospect portfolio, regulations have become more stringent due to the Deepwater Horizon incident of 2010. In some instances, specifically engineered blowout preventers, rigs, and completion equipment may be required for high pressure environments. Regulatory requirements or lack of readily available equipment could prevent us from engaging in future exploration activities during our current lease terms. In addition, the current low commodity price environment may render certain prospects economically less attractive and we may not conduct exploration activities before lease expiration.

In addition, new regulations are being considered by various federal agencies, including the BSEE and the BOEM, overseeing our activities in the Gulf of Mexico. These regulations, if ultimately adopted, could, among other things, significantly increase the costs associated with our activities in the Gulf of Mexico and result in some of our undrilled leasehold becoming uneconomic to drill and therefore written off. See Items 1. and 2. Business and Properties – Regulations – *US Offshore Regulatory Developments.*

We currently have capitalized undeveloped leasehold cost of approximately $247 million related to deepwater Gulf of Mexico prospects that have not yet been drilled. These leases will expire over the years 2016 - 2024 and some leases may become impaired if production is not established, we do not take action to extend the terms of the leases, or the leases become uneconomic due to low commodity prices, costs of complying with new regulations, or other factors.

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

Producing Properties In 2016, commodity prices, including WTI, Brent and HH, have continued to trade in a low range and remain volatile. A decline in future crude oil, natural gas or NGL prices could result in some of our properties becoming uneconomic, resulting in additional impairment charges, decrease in proved reserves and/or shut-in of currently producing wells.

In addition, in certain onshore US areas, transportation bottlenecks caused by oversupply and/or lack of infrastructure can reduce the amount of production reaching premium markets, resulting in higher basis differentials, or differences between WTI and HH pricing and the average prices we actually receive. An increase in these basis differentials could also reduce cash flows and result in property impairment charges.

The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future crude oil and natural gas production along with operating and development costs, market outlook on forward commodity prices, and interest rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward commodity prices, or increases in basis differentials, alone could result in an impairment.

In addition, well decommissioning programs, especially in deepwater or remote locations, are often complex and expensive. It may be difficult to estimate timing of actual abandonment activities, which are subject to regulatory approval, and the availability of rigs and services. It may be difficult to estimate costs as rigs and services become more expensive in periods of higher demand and less expensive in periods of low demand. Furthermore, regulations for decommissioning activities are under constant review for amendment and expansion and more stringent requirements are frequently mandated. Therefore, our ARO estimates may change, sometimes significantly, and could result in asset impairment.

See Items 1. and 2. Business and Properties.

Divestments We occasionally market certain properties. If properties are reclassified as assets held for sale in the future, they will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell.

Recently Issued Accounting Standards Updates See Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies.

Climate Change Climate change has become the subject of significant public policy debate. While climate change remains a complex technical issue, governments around the world have concluded that it poses an urgent and potentially irreversible threat and that global greenhouse gas emissions must be reduced to address that threat.

Our crude oil and natural gas exploration and production operations are a direct source of certain GHGs, namely carbon dioxide and methane, and an indirect source of GHGs from the combustion of our products. Future restrictions on the production, use, emission or combustion of hydrocarbons could have a significant impact on our operations. We therefore are actively monitoring the following climate change related issues:

Impact of Legislation and Regulation Among the commercial risks associated with the exploration and production of hydrocarbons is the uncertainty of government-imposed climate change obligations, including cap and trade schemes, carbon taxes, and other controls that may affect us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows, and could reduce the demand for our products.

In June 2013, President Obama unveiled a Presidential climate action plan designed to reduce carbon emissions in the US, prepare the US for potential climate change impacts, and lead international efforts to address potential global climate change. In furtherance of that plan, the Obama Administration has launched a number of initiatives, including the development of standards to increase vehicle fuel economy and a Strategy to Reduce Methane Emissions from the oil and gas industry. See also Items 1. and 2. Business and Properties – Regulations. We are continuing to monitor implementation of the Presidential climate change plan.

Impact of International Accords The Kyoto Protocol (Protocol) to the United Nations Framework Convention on Climate Change (Convention) went into effect in February 2005 and required all industrialized nations that ratified the Protocol to reduce or limit GHG emissions to a specified level by 2012. Certain parties then agreed to a second commitment period of the Kyoto Protocol which will last until December 31, 2020. Although a party to the Convention, the US did not ratify the Protocol.

Continuing international negotiations resulted in 195 countries, including the US, signing a new climate change agreement in Paris in 2015. While hailed as a significant political achievement, the Paris Agreement largely creates a foundation for further action. It aims to limit any increase in global temperature to less than 2°C greater than pre-industrial levels and to pursue efforts to limit the increase to 1.5°C. Parties are to submit their own nationally determined contributions toward GHG emissions reductions, which, unlike the reductions in the Protocol, will not be binding obligations. To help developing countries address climate change, moreover, the Paris Agreement sets a floor of $100 billion in annual aid collectively from developed countries. A new mitigation mechanism also will be developed over the next several years. The Paris Agreement will enter into force on the 30th day after being ratified by at least 55 parties representing at least 55% of global GHG emissions.

The US had submitted its emissions pledge in advance of the Paris Agreement. It sets an economy-wide target in 2025 of reducing GHG emissions by 26-28% as compared to 2005 levels, and to make best efforts to reach 28%. The Presidential climate action plan discussed above reportedly is expected to account for much, but not all, of the reduction.

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 or regulations.

Indirect Consequences of Regulation or Business Trends We believe there are both risks and opportunities arising from the global climate change initiatives. In terms of opportunities, the regulation of GHGs and introduction of formal technology incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways.

First, sales of natural gas comprised approximately 56% of our 2015 total sales volumes from continuing operations. The burning of natural gas produces lower levels of GHG emissions as compared to fuels such as liquid hydrocarbons and coal. In addition, public concern about nuclear safety has increased. These factors could increase the demand for natural gas as fuel for power generation. Also, should renewable resources, such as wind or solar power, become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply.

Second, market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could benefit us through the potential to obtain GHG allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Finally, future GHG standards for vehicles could result in the use of natural gas as transportation fuel. This may also increase the market demand for natural gas.

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. And to the extent that international efforts are not successful in preventing climate change, any resulting increase in severity or frequency of storms, rise in sea levels, extreme temperatures or other extreme environmental effects may have an adverse impact on our financial condition, results of operations and cash flows. See also Items 1. and 2. Business and Properties – Regulations and Item 1A. Risk Factors.

RESULTS OF OPERATIONS

In the discussion below, prior year amounts have been reclassified to reflect the North Sea segment as discontinued operations for the year ended December 31, 2013. As of January 1, 2014, the remaining North Sea assets were reclassified as assets held and used. See Discontinued Operations, below. Financial information presented is from continuing operations, unless otherwise noted.

Selected financial information is as follows:

	Year Ended December 31,		
	2015	2014	2013
(millions, except per share)			
Total Revenues	$ 3,133	$ 5,101	$ 5,015
Total Operating Expenses	5,605	4,183	3,359
Operating Income (Loss)	(2,472)	918	1,656
Total Other (Income) Expense	(253)	(792)	312
Income (Loss) from Continuing Operations Before Income Taxes	(2,219)	1,710	1,344
Income (Loss) from Continuing Operations	(2,441)	1,214	907
Discontinued Operations, Net of Tax	—	—	71
Net Income (Loss)	(2,441)	1,214	978
Earnings (Loss) from Continuing Operations Per Share			
Basic	(6.07)	3.36	2.53
Diluted	(6.07)	3.27	2.50

See following discussion for explanation of year-to-year changes.

Revenues

Oil, Gas and NGL Sales We generally sell crude oil, natural gas, and NGLs under two types of agreements common in our industry. Both types of agreements may include transportation charges. One type of agreement is a netback agreement, under which we sell crude oil and natural gas at the wellhead and receive a price, net of transportation expense incurred by the purchaser. In the case of NGLs, we may receive a price from the purchaser, which is net of processing costs. In this case, we record NGL revenue at the net price we receive from the purchaser. The second type of agreement is one whereby we pay transportation expense directly. In that case, transportation expense is included within production expense in our consolidated statements of operations.

In addition, commodity prices we receive may be reduced by location basis differentials, which can be significant. As a result of both netback agreements and location basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period.

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

	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
2013 Sales Revenues	$ 3,618	$ 976	$ 215	$ 4,809
Changes due to				
Increase in Sales Volumes	147	99	85	331
Increase (Decrease) in Sales Prices	(327)	148	(30)	(209)
2014 Sales Revenues	$ 3,438	$ 1,223	$ 270	$ 4,931
Changes due to				
Increase in Sales Volumes	306	241	181	728
Decrease in Sales Prices	(1,904)	(408)	(304)	(2,616)
2015 Sales Revenues	$ 1,840	$ 1,056	$ 147	$ 3,043

Changes in revenue are discussed below.

Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MMBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) [1]	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2015							
United States	81	708	39	237	$ 43.46	$ 2.10	$ 10.39
Equatorial Guinea [2]	31	227	—	69	48.85	0.27	—
Israel	—	252	—	42	—	5.34	—
Total Consolidated Operations	112	1,187	39	348	45.00	2.44	10.39
Equity Investees [3]	2	—	5	7	48.85	—	28.40
Total Continuing Operations	114	1,187	44	355	$ 45.05	$ 2.44	$ 12.48
Year Ended December 31, 2014							
United States	68	518	23	176	$ 89.60	$ 3.86	$ 32.04
Equatorial Guinea [2]	33	243	—	74	94.61	0.27	—
Israel	—	231	—	39	—	5.57	—
China	2	—	—	2	103.74	—	—
Total Consolidated Operations	103	992	23	291	91.58	3.38	32.04
Equity Investees [3]	2	—	5	7	96.53	—	62.89
Total Continuing Operations	105	992	28	298	$ 91.65	$ 3.38	$ 37.81
Year Ended December 31, 2013							
United States	63	440	16	153	$ 96.53	$ 3.54	$ 35.53
Equatorial Guinea [2]	32	252	—	73	107.48	0.27	—
Israel	—	209	—	35	—	5.02	—
China	4	—	—	4	103.21	—	—
Total Consolidated Operations	99	901	16	265	100.29	2.97	35.53
Equity Investees [3]	2	—	6	8	105.37	—	68.12
Total Continuing Operations	101	901	22	273	$ 100.38	$ 2.97	$ 43.90

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for US natural gas and NGLs are significantly less than the price for a barrel of crude oil. In Israel, we sell natural gas under contracts where the majority of the price is fixed, resulting in less commodity price disparity.

(2) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

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

Crude Oil and Condensate Sales Revenues from crude oil and condensate sales decreased by $1.6 billion, or 46%, in 2015 as compared with 2014 due to the following:

- a 51% decrease in total consolidated average realized prices primarily due to the decline in global crude oil prices that began in the second half of 2014 and continued in 2015;
- decrease in sales volumes due to planned downtime and maintenance as well as natural field decline in the deepwater Gulf of Mexico and the Aseng field, offshore Equatorial Guinea; and
- decrease in sales volumes due to the sale of our China assets at the end of second quarter 2014;

partially offset by:

- higher sales volumes of 7 MBbl/d in the DJ Basin primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;
- sales volumes of 7 MBbl/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- start up of the deepwater Gulf of Mexico Rio Grande development in fourth quarter 2015 which contributed 2 MBbl/d.

Revenues from crude oil and condensate sales decreased by $180 million, or 5%, in 2014 as compared with 2013 due to the following:

- a 9% decrease in total consolidated average realized prices primarily due to the NYMEX WTI crude oil price decline between June and December 2014, with a similar Brent crude oil price decline; and
- lower sales volumes due to the sale of our China assets at the end of second quarter 2014 and the sale of certain North Sea assets during 2013;

partially offset by:

- higher sales volumes of 4 MBbl/d in the DJ Basin primarily attributable to our horizontal drilling programs; and
- higher sales volumes of 2 MBbl/d in West Africa primarily due to the timing of crude oil and condensate liftings.

Natural Gas Sales Revenues from natural gas sales decreased by $167 million, or 14%, in 2015 as compared with 2014 due to the following:

- a 28% decrease in total consolidated average realized natural gas prices, including a 46% decrease in US average realized prices primarily due to oversupply; and
- a widening of location basis differentials in the Marcellus Shale due to an oversupply of natural gas in the region which lowered the price we received;

partially offset by:

- higher sales volumes of 28 MMcf/d in the DJ Basin primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;
- higher sales volumes of 131 MMcf/d in the Marcellus Shale primarily attributable to well completion and infrastructure development;
- sales volumes of 58 MMcf/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- record sales volumes from the Tamar field, offshore Israel, which contributed 21 MMcf/d, in response to higher power generation needs;

Revenues from natural gas sales increased by $247 million, or 25%, in 2014 as compared with 2013 due to the following:

- higher sales volumes of 123 MMcf/d in the Marcellus Shale primarily attributable to our horizontal drilling program and continued ramp-up of activity;
- higher sales volumes of 22 MMcf/d in the Eastern Mediterranean due to a full year of production from the Tamar field; and
- a 14% increase in total consolidated average realized prices primarily due to increased demand from cooler weather earlier in 2014 and higher-than-expected inventory withdrawals in the US during the first quarter of 2014, which increased the market price in our producing areas;

partially offset by:

- lower sales volumes due to non-core onshore US properties divested during 2013 and 2014.

NGL Sales Revenues from NGL sales decreased by $123 million, or 46%, in 2015 as compared with 2014 due to the following:

- a 68% decrease in total consolidated average realized NGL prices, which are closely linked to the NYMEX WTI crude oil price decline, particularly in the Marcellus Shale;

partially offset by:

- higher sales volumes of 2 MBbl/d in the DJ Basin primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;
- higher sales volumes of 5 MBbl/d in the Marcellus Shale primarily attributable to well completion and infrastructure development; and
- sales volumes of 9 MBbl/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets.

Revenues from NGL sales increased by $55 million, or 26%, during 2014 as compared with 2013 due to the following:

- higher sales volumes of 3 MBbl/d in the DJ Basin, due to increased horizontal drilling activity; and
- higher sales volumes of 4 MBbl/d in the Marcellus Shale, due to a full year of production from the wet gas acreage;

partially offset by:

- a 10% decrease in total consolidated average realized NGL prices, which are closely linked to the NYMEX WTI crude oil price declines between June and December 2014.

Income from Equity Method Investees We have interests in various equity method investees that operate midstream assets onshore US and West Africa. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, activity is reflected within cash flows provided by operating activities and cash flows provided by (used in) investing activities.

Our share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2015	2014	2013
Net Income (in millions)			
AMPCO and Affiliates	$ 8	$ 62	$ 85
Alba Plant	31	99	121
CONE Gathering and CONE Midstream	46	9	—
Other	5	—	—
Dividends (in millions)			
AMPCO and Affiliates	31	61	82
Alba Plant	29	117	122
CONE Gathering and CONE Midstream[1]	17	204	—
Sales Volumes			
Methanol (MMgal)	117	130	155
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	5	6
Average Realized Prices			
Methanol (per gallon)	$ 0.92	$ 1.26	$ 1.27
Condensate (per Bbl)	48.85	96.53	105.37
LPG (per Bbl)	28.40	62.89	68.12

[1] CONE Gathering distributed $204 million of dividends following the CONE Midstream IPO in 2014.

AMPCO and Affiliates Net income from AMPCO and affiliates decreased in 2015 as compared with 2014 primarily due to lower average realized methanol prices resulting from lower global demand and expenses associated with plant turnaround activities conducted first quarter 2015.

Net income from AMPCO and affiliates decreased in 2014 as compared with 2013 primarily due to a 16% decrease in methanol sales from plant interruptions in 2014 and higher storage of inventories to cover scheduled downtime for plant maintenance and upgrades in 2015.

Alba Plant Net income from Alba Plant in 2015 decreased as compared to 2014 primarily due to the decrease in the average realized sales price of condensate and LPG resulting from lower global demand.

Net income from Alba Plant in 2014 decreased as compared to 2013, primarily due to a decrease in the average realized sales price of condensate and LPG while sales volumes remained flat.

CONE Gathering and CONE Midstream On September 24, 2014, our equity method investee, CONE Gathering, contributed a significant majority of its existing assets to a newly-formed master limited partnership, CONE Midstream, concurrently with an initial public offering of limited partner units. CONE Gathering subsequently distributed $204 million of offering proceeds to us.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2015	Inc (Dec) from Prior Year	2014	Inc (Dec) from Prior Year	2013
Production Expense	$ 962	2 %	$ 947	12%	$ 844
Exploration Expense	488	(2)%	498	20%	415
Depreciation, Depletion and Amortization	2,131	21 %	1,759	12%	1,568
General and Administrative	396	(21)%	503	16%	433
Asset Impairments	533	7 %	500	481%	86
Goodwill Impairment	779	N/M	—	N/M	—
Other Operating (Income) Expense, Net	316	N/M	(24)	N/M	13
Total	$ 5,605	34 %	$ 4,183	25%	3,359

N/M amount is not meaningful.

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [(1)]	Total	United States	Equatorial Guinea	Israel	Other Int'l/ Corporate [(2)]
Year Ended December 31, 2015						
Lease Operating Expense [(3)]	$ 4.43	$ 563	$ 370	$ 131	$ 49	$ 13
Production and Ad Valorem Taxes	1.00	127	125	—	—	2
Transportation and Gathering Expense	2.13	272	272	—	—	—
Total Production Expense	$ 7.56	$ 962	$ 767	$ 131	$ 49	$ 15
Total Production Expense per BOE		$ 7.56	$ 8.87	$ 5.21	$ 3.15	N/M
Year Ended December 31, 2014						
Lease Operating Expense [(3)]	$ 5.58	$ 593	$ 343	$ 147	$ 54	$ 49
Production and Ad Valorem Taxes	1.73	184	166	—	—	18
Transportation and Gathering Expense	1.60	170	168	—	—	2
Total Production Expense	$ 8.91	$ 947	$ 677	$ 147	$ 54	$ 69
Total Production Expense per BOE		$ 8.91	$ 10.55	$ 5.44	$ 3.84	N/M
Year Ended December 31, 2013						
Lease Operating Expense [(3)]	$ 5.46	$ 524	$ 337	$ 106	$ 48	$ 33
Production and Ad Valorem Taxes	1.94	188	154	—	—	34
Transportation and Gathering Expense	1.36	132	129	—	—	3
Total Production Expense	$ 8.76	$ 844	$ 620	$ 106	$ 48	$ 70
Total Production Expense per BOE		$ 8.76	$ 11.21	$ 3.97	$ 3.75	N/M

N/M Amount is not meaningful.

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

(2) Other International, Corporate includes the North Sea (in 2014 and 2015), China (through June 30, 2014) and corporate expenditures.

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

Lease operating expense decreased in 2015 as compared with 2014 due to the following:

- decrease of $17 million from sales of non-core onshore US properties in 2014;
- decrease of $17 million due to the sale of our China assets at the end of second quarter 2014;
- decrease of $15 million in deepwater Gulf of Mexico due to cessation of operations at South Raton, natural field decline and cost reduction initiatives;
- decrease of $15 million offshore West Africa due to cost reduction initiatives and lower production;
- decrease of $6 million in offshore Israel due to cost reduction initiatives; and
- decrease of $9 million in other international/corporate due to cost reduction initiatives;

partially offset by:

- increase of $38 million attributable to our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- increase of $11 million in the Marcellus Shale due to increased production.

Lease operating expense increased in 2014 as compared with 2013 due to the following:

- increases of $63 million in the DJ Basin and $5 million in the Marcellus Shale due to increased development activity resulting in higher production;
- increase of $41 million offshore Equatorial Guinea primarily driven by a full year of labor and FPSO expense resulting from the start up of the Alen field during the second half of 2013;
- increase of $7 million offshore Israel primarily driven by a full year of expense for the Tamar field, which began producing at the end of first quarter 2013; and
- increase of $15 million other international and corporate due to inclusion of North Sea in continuing operations during 2014, which was included in discontinued operations in 2013;

partially offset by:

- decrease of $45 million due to the acquisition of the Neptune facility in deepwater Gulf of Mexico;
- decrease of $10 million from sales of non-core onshore US properties in 2014;
- decrease of $8 million from the sale of our China assets at the end of second quarter 2014; and
- decrease of $1 million from natural field decline from the Mari-B field, offshore Israel.

See also *Discontinued Operations*, below.

Production and Ad Valorem Tax Expense Production and ad valorem taxes decreased in 2015 as compared with 2014, primarily driven by lower revenues resulting from the decline in commodity prices in the US as well as a reduction of $17 million resulting from the sale of our China assets at the end of the second quarter 2014.

Production and ad valorem tax expense decreased in 2014 as compared with 2013, primarily driven by a reduction of $17 million resulting from the sale of our China assets at the end of the second quarter 2014 along with a decrease in average realized crude oil prices between June and December 2014. This decrease was partially offset by higher taxes of $12 million in the DJ Basin and Marcellus Shale due to increased revenues resulting from higher production volumes and higher average realized natural gas prices.

Transportation Expense Transportation expense increased in 2015 as compared with 2014 related to an increase of $81 million in the Marcellus Shale due to higher production and increased expenses due to service contracts with CONE Gathering, an increase of $33 million due to recently-acquired Eagle Ford Shale and Permian Basin properties and an increase of $12 million in the DJ Basin due to the May 2015 commencement of Tallgrass pipeline, which transports DJ Basin crude oil. Increases were offset by $8 million decrease due to the sale of non-core onshore US, China and North Sea properties in 2014.

Transportation expense increased in 2014 as compared with 2013 related to an increase of $44 million in the DJ Basin and Marcellus Shale due to higher production volumes from ongoing development activities offset by an $8 million decrease primarily due to the sale of non-core onshore US, China and North Sea properties in 2013 and 2014.

Unit Rate Per BOE The unit rate of total production expense per BOE decreased for 2015 as compared with 2014 primarily due to lower production and ad valorem taxes as a result of the pricing environment in addition to cost reduction initiatives in lease operating expense and higher production volumes.

The unit rate of total production expense per BOE increased for 2014 as compared with 2013 primarily due to a change in the mix of production. Higher-cost production volumes in the DJ Basin and deepwater Gulf of Mexico were offset by lower cost volumes produced in the Marcellus Shale, Equatorial Guinea and Israel.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediterranean (2)	Other Int'l, Corporate (3)
Year Ended December 31, 2015					
Dry Hole Cost	$ 266	$ 93	$ 33	$ —	$ 140
Seismic	18	3	9	—	6
Exploration Overhead and Staff Expense	154	57	4	12	81
Other (4)	50	50	—	—	—
Total Exploration Expense	$ 488	$ 203	$ 46	$ 12	$ 227
Year Ended December 31, 2014					
Dry Hole Cost	$ 226	$ 147	$ —	$ —	$ 79
Seismic	64	24	16	4	20
Exploration Overhead and Staff Expense	154	43	10	13	88
Other (4)	54	54	—	—	—
Total Exploration Expense	$ 498	$ 268	$ 26	$ 17	$ 187
Year Ended December 31, 2013					
Dry Hole Cost	$ 149	$ 20	$ 8	$ —	$ 121
Seismic	97	31	3	18	45
Exploration Overhead and Staff Expense	128	33	9	6	80
Other (4)	41	40	—	—	1
Total Exploration Expense	$ 415	$ 124	$ 20	$ 24	$ 247

(1) West Africa includes Equatorial Guinea, Cameroon and Gabon.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other International, Corporate includes the Falkland Islands, Suriname and other new ventures and corporate expenditures.
(4) Includes unproved leasehold amortization expense of $43 million in 2015, $43 million in 2014, and $30 million in 2013.

Oil and gas exploration expense decreased in 2015 as compared with 2014. Expense for 2015 includes the following:

- US dry hole cost includes amounts related to northeast Nevada exploration efforts which we elected to discontinue after assessing commercial viability in the current commodity price environment;
- West Africa dry hole cost includes the Cheetah well (offshore Cameroon) and Other International dry hole cost includes the Humpback well (offshore Falkland Islands), neither of which identified commercial quantities of hydrocarbons; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Oil and gas exploration expense increased in 2014 as compared with 2013. Expense for 2014 includes the following:

- dry hole cost related to the following exploratory wells which did not locate commercial quantities of hydrocarbons: Comanche Plains (onshore US); Bright (deepwater Gulf of Mexico); Madison (deepwater Gulf of Mexico); and Scotia (offshore Falkland Islands);
- seismic expense related to the acquisition of 3D seismic data in the deepwater Gulf of Mexico, Equatorial Guinea, and Falkland Islands; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense included stock-based compensation expense of $13 million in 2015, $17 million in 2014 and $15 million in 2013.

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

	Year Ended December 31,		
(millions, except unit rate)	2015	2014	2013
United States	$ 1,692	$ 1,318	$ 1,117
Equatorial Guinea	326	299	261
Israel	70	63	97
Other International, and Corporate	43	79	93
Total DD&A Expense (1)	$ 2,131	$ 1,759	$ 1,568
Unit Rate per BOE (2)	$ 16.75	$ 16.55	$ 16.18

(1) DD&A expense includes accretion of discount on asset retirement obligations of $43 million in 2015, $36 million in 2014, and $26 million in 2013.

(2) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

Total DD&A expense increased for 2015 as compared with 2014 due to the following:

- increase of $332 million in the DJ Basin and Marcellus Shale due to higher sales volumes and a reduction in proved reserves at year end primarily due to downward price revisions;
- increase of $93 million related to our recently-acquired Eagle Ford Shale and Permian Basin assets;
- increase of $55 million related to the Rio Grande development, deepwater Gulf of Mexico, which began producing in 2015;
- increase in Equatorial Guinea due to a reduction in proved reserves at year end primarily due to downward price revisions; and
- increase due to record sales volumes from the Tamar field, offshore Israel;

partially offset by:

- decrease of $92 million in the deepwater Gulf of Mexico due to planned downtime and maintenance and proved reserves additions; and
- decrease due to the sale of our China assets during 2014.

Changes in the unit rate per BOE for 2015 as compared with 2014 were due to increased higher-cost production volumes in the DJ Basin and deepwater Gulf of Mexico, reductions in proved reserves at year-end due to downward price revisions, offset by increased lower-cost production volumes from the Tamar field.

Total DD&A expense increased for 2014 as compared with 2013 due to the following:

- higher sales volumes associated with increased development activity in the DJ Basin and the Marcellus Shale accounted for increases of $109 million and $95 million, respectively;
- increase of $15 million in the deepwater Gulf of Mexico due to a full year of production for a new well at Ticonderoga and the addition of the Neptune spar at Swordfish;
- increase of $38 million offshore Equatorial Guinea primarily due to a full year of production at the Alen field;
- increase of $15 million due to a full year of production at the Tamar field, offshore Israel;
- increase of $11 million due to North Sea properties reclassified to continuing operations for 2014; and
- increase of $16 million associated with corporate assets;

partially offset by:

- decrease of $32 million due to sales of non-core onshore US properties in 2014 and 2013;
- decrease of $49 million from natural field decline at the Mari-B, Noa and Pinnacles fields, offshore Israel; and
- decrease of $35 million due to sale of China assets in 2014.

Changes in the unit rate per BOE for 2014 as compared with 2013 were due to change in mix of production. Higher-cost production volumes in the DJ Basin and deepwater Gulf of Mexico were offset by lower cost volumes produced at Tamar.

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

	Year Ended December 31,		
	2015	2014	2013
G&A Expense (millions)	$ 396	$ 503	$ 433
Unit Rate per BOE [1]	$ 3.11	$ 4.73	$ 4.47

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

G&A expense for 2015 decreased as compared with 2014 primarily due to cost savings initiatives, including reduced use of contractors and consultants and decreases in special projects and other discretionary expenses, and decreases in employee personnel costs. Our total number of employees decreased from 2,735 at December 31, 2014 to 2,395 at December 31, 2015.

G&A expense for 2014 increased as compared with 2013 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and exploration activities. For example, our total number of employees increased from 2,527 at December 31, 2013 to 2,735 at December 31, 2014. Increases in G&A were offset by a decrease in G&A due to reduced employee incentive compensation.

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 the Black-Scholes-Merton option pricing model. G&A included stock-based compensation expense of $50 million in 2015, $63 million in 2014 and $58 million in 2013. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

Asset Impairments Asset impairment expense was as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Asset Impairments	$ 533	$ 500	$ 86

For information regarding asset impairment charges, see Critical Accounting Policies and Estimates – Impairment of Proved Oil and Gas Properties and Other Investments and Impairment of Unproved Oil and Gas Properties and Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Goodwill Impairment Goodwill impairment expense was as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Goodwill Impairment	$ 779	$ —	$ —

For information regarding goodwill impairment charges, see Critical Accounting Policies and Estimates – Goodwill and Item 8. Financial Statements and Supplementary Data – Note 4. Goodwill.

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

	Year Ended December 31,		
(millions)	2015	2014	2013
Midstream Gathering and Processing Expense, Net	$ 9	$ 11	$ 6
Corporate Restructuring Expense	51	—	—
Stacked Drilling Rig Expense	30	—	—
Pension Plan Expense	88	—	—
Rosetta Merger Expenses	81	—	—
(Gain) on Divestitures	—	(73)	(36)
Inventory Adjustment	20	—	—
Other, Net	37	38	43
Total	$ 316	$ (24)	$ 13

See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

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

	Year Ended December 31,		
(millions)	2015	2014	2013
(Gain) Loss on Commodity Derivative Instruments	$ (501)	$ (976)	$ 133
Interest, Net of Amount Capitalized	263	210	158
Other Non-Operating (Income) Expense, Net	(15)	(26)	21
Total	$ (253)	$ (792)	$ 312

See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

(Gain) Loss on Commodity Derivative Instruments (Gain) Loss on commodity derivative instruments is a result of mark-to-market accounting. Many factors impact our (gain) loss on commodity derivative instruments including: increases and decreases in the commodity forward price curves compared with our executed hedging arrangements; increases in hedged future volumes; and the mix of hedge arrangements between NYMEX WTI, Dated Brent and NYMEX HH commodities. See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities and Note 13. Fair Value Measurements and Disclosures.

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

	Year Ended December 31,		
(millions, except per unit)	2015	2014	2013
Interest Expense	$ 407	$ 326	$ 279
Capitalized Interest	(144)	(116)	(121)
Interest Expense, Net	$ 263	$ 210	$ 158
Unit Rate per BOE [1]	$ 2.07	$ 1.97	$ 1.63

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

Interest expense prior to the reduction of capitalized interest increased in 2015 as compared with 2014. The increase in interest expense is related to a full year of interest on senior debt issued in November 2014, as well as interest on senior notes assumed by us in the Rosetta Merger during third quarter 2015. We drew down and repaid amounts under our Credit Facility for working capital purposes. There were no other significant changes in our debt.

Interest expense prior to the reduction of capitalized interest increased in 2014 as compared with 2013. Interest related to a full year of interest on senior debt issued in November 2013, as well as interest related to senior debt issued in November 2014 was offset by a reduction in interest related to repayment of an installment loan. We drew down and repaid amounts under our Credit Facility for working capital purposes. There were no other significant changes in our debt.

Interest capitalized in 2015 increased as compared with 2014. The increase is primarily due to higher work in progress amounts related to major long-term projects in deepwater Gulf of Mexico, offshore West Africa, and offshore Israel, as well as expansion of midstream infrastructure in the DJ Basin.

Interest capitalized in 2014 decreased slightly as compared with 2013. The decrease is due primarily to the completion of major projects at Alen and Tamar in 2013 offset by higher work in progress amounts related to major long-term projects onshore US and deepwater Gulf of Mexico.

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 the deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense, net. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

Deferred Compensation (Income) Expense We have assets and liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of our common stock and mutual fund investments. At December 31, 2015, approximately 36% of the market value of the assets in the rabbi trust related to our common stock. Increases in the market value of our common stock held in the trust result in the recognition of deferred compensation expense. Decreases in the market value of our common stock held in the trust result in the recognition of deferred compensation income. We recognized deferred compensation income of $12 million and $25 million in 2015 and 2014, respectively, and deferred compensation expense of $26 million in 2013. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

Income Tax Provision The income tax provision from continuing operations was as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Income Tax Provision	$ 222	$ 496	$ 437
Effective Rate	(10.0)%	29.0%	32.5%

See Item 8. Financial Statements and Supplementary Data – Note 11. Income Taxes.

Discontinued Operations

Summarized results of discontinued operations, comprising our North Sea geographical segment during 2013, were as follows:

	Year Ended December 31,
(millions)	2013
Oil and Gas Sales	$ 37
Less:	
Production Expense	19
DD&A Expense	2
Other (Income) Expense, Net	4
Income Before Income Taxes	12
Income Tax Expense	6
Operating Income, Net of Tax	6
Gain on Sale, Net of Tax	65
Discontinued Operations, Net of Tax	$ 71
Key Statistics:	
Daily Production	
Crude Oil & Condensate (MBbl/d)	1
Natural Gas (MMcf/d)	2
Average Realized Price	
Crude Oil & Condensate (Per Bbl)	$ 108.73
Natural Gas (Per Mcf)	$ 10.65

Our long-term debt is recorded at the consolidated level and is not reflected by each component. Thus, we did not allocate interest expense to discontinued operations.

See Item 8. Financial Statements and Supplementary Data – Note 3. Merger, Acquisitions and Divestitures.

PROVED RESERVES

We have historically added reserves through our exploration program, development activities, and acquisition of producing properties. See Items 1. and 2. Business and Properties. Changes in proved reserves were as follows:

	Year Ended December 31,		
	2015	2014	2013
(MMBoe)			
Proved Reserves Beginning of Year	1,404	1,406	1,184
Revisions of Previous Estimates	(216)	21	95
Extensions, Discoveries and Other Additions	100	120	250
Purchase of Minerals in Place	269	—	24
Sale of Minerals in Place	(6)	(33)	(47)
Production	(130)	(110)	(100)
Proved Reserves End of Year	1,421	1,404	1,406

Revisions Revisions of previous estimates represent changes in previous reserves estimates, either upward (positive) or downward (negative), resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, or development costs. Revisions included the following:

- changes for the year ended December 31, 2015 include negative revisions of 307 MMBoe due to lower commodity prices, downward revisions of 9 MMBoe and 5 MMBoe for the DJ Basin and Eagle Ford Shale, respectively, primarily due to current drilling and development plans in the DJ Basin and expected reserve recovery from existing producing wells in the Eagle Ford Shale, and downward revisions of 3 MMBoe due to natural field decline from the Mari-B field, offshore Israel; offset by positive performance revisions of 81 MMBoe for the Marcellus Shale, 17 MMBoe for the Permian Basin and 10 MMBoe for Alba field;
- changes for the year ended December 31, 2014 included positive performance revisions of 18 MMBoe for the Marcellus Shale, 4 MMBoe for deepwater Gulf of Mexico, 4 MMBoe for Alba field, and 3 MMBoe for the Tamar field; offset by a downward revision of 8 MMBoe for the DJ Basin primarily due to planned reduction in pace of drilling activity due to lower commodity prices; and
- changes for the year ended December 31, 2013 included positive performance revisions of 48 MMBoe for the DJ Basin and Marcellus Shale, 11 MMBoe for the Alba field, and 21 MMBoe for the Tamar field; and positive price revisions of 13 MMBoe due to higher commodity prices.

Extensions, Discoveries and Other Additions These are additions to proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions included the following:

- changes for the year ended December 31, 2015 include increases of 86 MMBoe in the DJ Basin and 14 MMBoe in the Marcellus Shale associated with our horizontal drilling programs;
- changes for the year ended December 31, 2014 included increases of 47 MMBoe in the DJ Basin, 62 MMBoe in the Marcellus Shale, and 10 MMBoe deepwater Gulf of Mexico primarily attributable to sanction of the Dantzler development. The decrease in the DJ Basin changes from prior years is primarily due to the reduced pace of drilling activity in response to the lower commodity price outlook; and
- changes for the year ended December 31, 2013 included increases of 130 MMBoe in the DJ Basin, 61 MMBoe in the Marcellus Shale, 18 MMBoe deepwater Gulf of Mexico primarily attributable to the sanction of the Big Bend and Gunflint developments, 8 MMBoe in Equatorial Guinea attributable to the Alba and Aseng fields, 30 MMBoe in Israel attributable to the discovery and sanction of the Tamar Southwest field, and 2 MMBoe associated with other development programs.

We expect that a significant portion of future reserves additions will come from our major development projects onshore US and deepwater Gulf of Mexico, and new discoveries resulting from our exploration programs in core areas as well as global new ventures programs. We may also purchase proved properties in strategic acquisitions. See Operating Outlook – Major Development Project Inventory, above, and Liquidity and Capital Resources – Acquisition, Capital and Other Exploration Expenditures, below.

Purchase of Minerals in Place We occasionally enhance our asset portfolio with strategic acquisitions of producing properties. Purchases included the acquisition of additional acreage primarily in the Eagle Ford Shale and Permian Basin in Texas in 2015, in connection with the Rosetta Merger, and the Marcellus Shale and DJ Basin in 2013.

Sale of Minerals in Place We maintain an ongoing portfolio management program. Sales included the following:

- the sale of non-core onshore US assets in 2015;
- the sale of non-core onshore US and China assets in 2014; and
- the sale of non-core onshore US and North Sea assets and the net impact of the DJ Basin acreage exchange in 2013.

See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 3. Merger, Acquisitions and Divestitures.

Production See Results of Operations – Revenues – *Oil, Gas and NGL Sales,* above.

See also Items 1. and 2. Business and Properties, Critical Accounting Policies and Estimates – Reserves, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our discovered hydrocarbons, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the volatile commodity price cycle, including the current commodity price environment. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a continuing exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity.

We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives. We utilize a commodity price hedging program to reduce the impacts of commodity price volatility and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and the funding of our business.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash flows from operations, cash on hand, available borrowing capacity under our Credit Facility, and proceeds from sales of non-core properties.

We occasionally access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Credit Facility or to refinance scheduled debt maturities. We consider repatriations of foreign cash to increase our financial flexibility and fund our capital investment program. In addition, we evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending and may consider non-core asset sales or other sources of funding.

During 2015, we were able to employ the above strategy successfully, taking steps to position us for long-term operational performance and future growth even in a period of lower commodity prices. See Activities Enhancing Liquidity Position, below. During 2015, low commodity prices resulted in a reduction in our capital spending program, had significant negative impacts on our revenues, profitability, and cash flows and led to a reduction in our stock price. In January 2016, our Board of Directors declared a reduced quarterly cash dividend in response to our comprehensive effort to spend within cash flow and also align the dividend yield with historical levels. However, a sustained or more severe commodity price downturn could result in material negative impacts on our cash flows and liquidity. See Item 1A. Risk Factors - *We are currently experiencing a severe downturn in the oil and gas business cycle, and an extended or more severe downturn could have material adverse effects on our results of operations, our liquidity, and the price of our common stock.*

Activities Enhancing Liquidity Position

During 2015 and early 2016, the following activities enhanced our liquidity position:

Common Stock Issuance In March 2015, we closed an underwritten public offering of over 24 million shares of common stock with aggregate net proceeds of approximately $1.1 billion (after deducting underwriting discounts and commissions and estimated offering expenses). We used approximately $150 million of the net proceeds to repay outstanding indebtedness under our revolving Credit Facility and the remainder was used for general corporate purposes, including the funding of our capital investment program.

Maturity Date Extension During 2015, we extended the maturity date of the Credit Facility from October 3, 2018 to August 27, 2020.

Cash Dividend Repatriations During 2015, we repatriated cash dividends of $858 million from our foreign operations. We do not expect to incur significant cash tax on these repatriations due to usage of foreign tax credits and current US tax deductions.

As of December 31, 2015, approximately $457 million of our $1.0 billion cash and cash equivalents was held by foreign subsidiaries.

Non-Core Asset Sales and Other Divestitures During 2015, we generated $151 million cash from divestitures of non-core onshore US assets. More recently, in January 2016, we received over $190 million cash from the close of our Cyprus farmout and sale of Tanin and Karish discoveries.

Debt Refinancing Also in January 2016, we completed a series of transactions, consisting of a new term loan and cash tender offers for certain outstanding notes, which we expect will collectively enhance our financial flexibility and result in future interest expense savings. See Financing Activities, below.

Dividend Reduction On January 26, 2016, our Board of Directors adjusted the quarterly dividend to 10 cents per common share, which represents a reduction of 8 cents from fourth quarter 2015, aligns the dividend yield with historical levels, and further enhances our liquidity.

Available Liquidity

Year-end liquidity was as follows:

	December 31,		
	2015	2014	2013
(millions, except percentages)			
Cash and Cash Equivalents	$ 1,028	$ 1,183	$ 1,117
Amount Available to be Borrowed Under Credit Facility (1)	4,000	4,000	4,000
Total Liquidity	$ 5,028	$ 5,183	$ 5,117
Total Debt (2)	$ 7,976	$ 6,197	$ 4,843
Total Shareholders' Equity	10,370	10,325	9,184
Ratio of Debt-to-Book Capital (3)	43%	38%	35%

(1) See *Credit Facility,* below.

(2) Total debt includes capital lease and other obligations and excludes unamortized debt discount, premium, and issuance costs.

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

Current Activity - Impact on Liquidity

Despite a 42% reduction in capital spending, excluding the Rosetta Merger, in 2015 versus 2014, and significant decreases in operating and general and administrative expenses, continually falling commodity prices resulted in capital expenditures exceeding operating cash flows for fiscal year 2015. For 2016, our comprehensive effort to spend within cash flow includes both a substantially reduced and flexible capital program, as well as a dividend adjustment. In January 2016, our Board of Directors adjusted the Company's quarterly cash dividend to 10 cents per common share, which represents a reduction of 8 cents from fourth quarter 2015 and aligns the dividend yield with historical levels.

The extent to which capital investment could exceed operating cash flows in the future depends on the pace of future development activities, timing of future development project sanction, the results of our exploration activities, and new business opportunities, as well as external factors such as commodity prices, among others.

Despite the low commodity price environment, we believe our financial capacity, coupled with our increasingly diversified portfolio, provides us with flexibility in our investment decisions including execution of major development projects as well as exploration activity in the current commodity price environment. See Operating Outlook – 2016 Capital Investment Program, above.

To support our investment program, we expect that production resulting from our core onshore US development programs, including production from our Texas assets, combined with new production from the Big Bend and Dantzler development projects, which have recently begun producing, and from the Gunflint development, which is expected to begin producing in 2016, as well as increased peak deliverability resulting from the Tamar compression project, and presuming no significant further deterioration of prices, will result in an increase in cash flows which will be available to meet a portion of future capital commitments in 2016 and subsequent years.

We are currently evaluating potential development and/or financing scenarios for significant discoveries, including the Leviathan development project offshore Eastern Mediterranean. The magnitude of certain discoveries presents technical and financial challenges for us due to the large-scale development requirements. Some development options, such as development of Leviathan Phase 1, require a multi-billion dollar investment and require a number of years to complete.

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 2016. However, a downgrade or other negative action with respect to our credit rating could trigger requirements to post collateral as financial assurance of performance under certain contractual arrangements potentially impacting our liquidity and/or negatively impacting our cost, terms, conditions and availability of future financing. See Item 1A. Risk Factors – *A downgrade or other negative action with respect to our credit rating could negatively impact our business and financial condition.*

Cash and Cash Equivalents We had approximately $1.0 billion in cash and cash equivalents at December 31, 2015, compared with approximately $1.2 billion at December 31, 2014. At December 31, 2015, our cash was primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $457 million of this cash was attributable to foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credits.

Credit Facility We maintain a Credit Facility with a committed amount of $4.0 billion through 2020. We expect to use the Credit Facility to fund our capital investment program, and may periodically borrow amounts for working capital purposes. No amounts were drawn under the Credit Facility at December 31, 2015. See Financing Activities – *Long-Term Debt* below.

Derivative Instruments We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments may include variable to fixed price commodity swaps, enhanced swaps, two-way and three-way collars, basis swaps and/or put options.

Our practice has been to hedge up to 50% of forecasted hedgeable global crude oil and domestic natural gas production for the current year plus two additional calendar years. The limit was increased to up to a maximum of 75% of forecasted hedgeable global crude oil production for the years 2014 and 2015. Our 2016 hedges cover approximately 35% of our expected global crude oil and 25% of our expected US natural gas production.

As of December 31, 2015, the fair value of our commodity derivative assets was $592 million and the fair value of our commodity derivative liabilities was zero (after consideration of netting clauses within our master agreements). We net settle by counterparty based on master agreements. Net settlements take into account deferred premiums we have agreed to pay for put options. None of our counterparty agreements contain margin requirements.

See Item 1A. Risk Factors – *Commodity, interest rate and exchange rate hedging transactions may limit our potential gains,* Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Counterparty Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedge counterparties, and financial institutions on an ongoing basis. Counterparty credit downgrades or liquidity problems could result in a delay in our receiving proceeds from commodity sales, reimbursement of joint venture costs, and potential delays in our major development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. Our projects are capital cost 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.

We are unable to predict sudden changes in a party's creditworthiness or ability to perform. Even if we do accurately predict such sudden changes, our ability to negate these risks may be limited and we could incur significant financial losses.

Credit enhancements have been obtained from some parties in the form of parental guarantees, letters of credit or credit insurance; however, not all of our counterparty credit is protected through guarantees or credit support. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a trade creditor, hedge counterparty or financial institution could result in significant financial losses. See Item 1A. Risk Factors – *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions and cash investments.*

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2015	2014	2013
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 2,062	$ 3,506	$ 2,937
Investing Activities	(2,871)	(4,465)	(3,675)
Financing Activities	654	1,025	468
Increase (Decrease) in Cash and Cash Equivalents	$ (155)	$ 66	$ (270)

Operating Activities Net cash provided by operating activities for 2015 decreased $1.4 billion, or 41%, as compared with 2014. Lower revenues, resulting from continuing declines in crude oil, natural gas and NGL prices, were offset by decreases in production expense, general and administrative expense and cash received in settlement of our commodity derivative instruments. An increase in interest expense is due to the senior notes we assumed in the Rosetta Merger during the third quarter 2015 and debt issued in November 2014. In addition, changes in working capital, including decreases in accounts receivable and accounts payable balances contributed to a net positive offset to the decrease in operating cash flows. See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows.

Net cash provided by operating activities for 2014 increased $569 million, or 19%, as compared with 2013. Higher revenues, driven by an increase in sales volumes and higher natural gas prices, were offset by impacts of declining crude oil prices, increases in production expense, general and administrative expense and interest expense. In addition, changes in working capital, including a decrease in accounts receivable and an increase in accounts payable balances, contributed to an increase in operating cash flows. See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows.

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

Capital spending for property, plant and equipment totaled $3.0 billion in 2015, representing a decrease of $1.9 billion as compared with 2014, primarily due to decreased major project development activity in core areas. We received $151 million proceeds from non-core asset divestitures during 2015 as compared with $321 million proceeds from divestitures during 2014, and acquired cash of $61 million in the Rosetta Merger. We also invested $104 million in CONE Gathering in 2015.

Capital spending for property, plant and equipment totaled $4.9 billion in 2014, representing an increase of $924 million as compared with 2013, primarily due to increased major project development activity in core areas. We invested $71 million in CONE Gathering, and received cash distributions of $156 million, accounted for as investing activity, from CONE Midstream, during 2014. We also received $321 million proceeds from non-core asset divestitures during 2014 as compared with $327 million proceeds from divestitures during 2013.

In 2013, our capital spending for property, plant and equipment totaled $3.9 billion. A significant portion of the spending related to major project development activity in our core areas. We also invested $48 million in CONE Gathering during 2013. We received $327 million proceeds from non-core asset divestitures, an acreage exchange, and farm-out agreements during 2013.

Financing Activities Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings.

In 2015, net cash provided by financing activities was $654 million. We received approximately $1.1 billion net proceeds from the issuance of shares of common stock in a public offering. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($7 million). We used cash to pay dividends on our common stock ($291 million), make principal payments related to capital lease obligations ($67 million), and repurchase shares of our common stock ($21 million). Subsequent to the Rosetta Merger, we incurred financing cash outflows to facilitate the exchange of Rosetta's debt ($12 million) as well as repay the balance outstanding under Rosetta's credit facility ($70 million).

In 2014, net cash provided by financing activities was $1.0 billion. We received approximately $1.5 billion net proceeds from the issuance of senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($67 million). We used cash to repay senior notes due ($200 million), pay dividends on our common stock ($249 million), make principal payments related to capital lease obligations ($55 million), and repurchase shares of our common stock ($16 million).

In 2013, net cash provided by financing activities was $468 million. We received $985 million net proceeds from the issuance of our 5.25% senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($71 million). We used cash to make an installment payment ($328 million), pay dividends on our common stock ($198 million), make principal payments related to a capital lease obligation ($48 million), and repurchase shares of our common stock ($14 million).

Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2015	2014	2013
(millions)			
Acquisition, Capital and Exploration Expenditures			
Proved Property Acquisition (1)	$ 1,613	$ —	$ —
Unproved Property Acquisition (2)	1,480	249	208
Exploration	322	505	871
Development	2,055	3,660	2,826
Midstream(3)	356	229	170
Corporate and Other	97	169	188
Total	$ 5,923	$ 4,812	$ 4,263
Other			
Investment in Equity Method Investee (4)	$ 104	$ 71	$ 48
Increase in Capital Lease Obligations (5)	55	110	76

(1) Proved property acquisition cost relates to proved properties acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Merger, Acquisitions and Divestitures.

(2) Unproved property acquisition cost for 2015 primarily relates to unproved properties acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Merger, Acquisitions and Divestitures. Additionally, unproved property acquisition cost for 2015 includes $49 million in the DJ Basin, $60 million in the Marcellus Shale, and $10 million and $5 million for costs incurred after the Rosetta Merger in the Permian Basin and Eagle Ford Shale, respectively.
Unproved property acquisition cost for 2014 includes $68 million in the DJ Basin, $160 million in the Marcellus Shale and $16 million in the deepwater Gulf of Mexico.

Unproved property acquisition cost for 2013 includes $27 million in the DJ Basin, $166 million in the Marcellus Shale and $12 million in the deepwater Gulf of Mexico.

(3) 2015 includes gathering and processing assets acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Merger, Acquisitions and Divestitures.

(4) We own a 50% interest in CONE Gathering which is accounted for using the equity method. CONE Gathering constructs, owns and operates gathering lines and facilities related to the Marcellus Shale development.

(5) Relates to estimated construction in progress on onshore US assets.

Excluding the Rosetta Merger, total expenditures decreased in 2015 as compared with 2014 due to our reduced capital spending program. Given the 2015 commodity price environment and an industry cost structure that had yet to fully reset to lower revenue levels, we designed a substantially reduced capital investment program that was appropriate for the price environment.

Total expenditures increased in 2014 as compared with 2013 due to accelerated activity in the DJ Basin and Marcellus Shale and included approximately $193 million related to the CONSOL Carried Cost Obligation.

Asset Divestitures Non-core asset divestitures generated cash proceeds of $151 million in 2015, $321 million in 2014 and $327 million in 2013.

Risk and Insurance Program

Our business is subject to all of the inherent and unplanned operating risks normally associated with the exploration, production, gathering, processing, transportation and marketing of crude oil, natural gas and NGLs. Such risks include hurricanes, blowouts, well cratering, fire, loss of well control, pipeline disruptions, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals, any of which could result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, environmental pollution, injury to persons, or loss of life. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production income), employer's liability, third party liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and 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.

Limits and deductibles were revised for the property and business interruption programs, as well as the excess liability program, in 2015.

We carry some business interruption insurance for loss of production income arising from physical damage to our major facilities. The coverage is subject to customary deductibles, waiting periods and recovery limits. We also maintain credit insurance to mitigate commodity receivables concentration risk.

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. 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 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.

In the Gulf of Mexico, we self-insure for windstorm related exposures, unless contractually required to purchase windstorm coverage for third party facilities. Currently, our Gulf of Mexico assets are primarily subsea operations; therefore, our direct windstorm exposure is limited. However, we do have some exposure through the use of third party production platforms and one Noble-owned floating production facility. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. As a result, we currently believe it is more cost-effective for us to self-insure, or absorb any physical loss or damage to these assets, including any business interruption attributable to windstorm exposures. We continually assess our offshore insurance needs in response to our changing business requirements.

As is customary with industry practice, crude oil and natural gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our US and international drilling contracts contain such indemnification clauses. In addition, crude oil and natural gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry more than $1.05 billion in insurance protection, depending on our ownership interest, for potential financial losses occurring as a result of events such as the Deepwater Horizon incident of 2010. This protection consists of $850 million of well control, pollution cleanup and consequential damages coverage and more than $200 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death.

We have contracts with third-party service providers to perform hydraulic fracturing operations for us. The master service agreements signed by hydraulic fracturing contractors contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusion for liabilities from hydraulic fracturing operations and we believe our policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. We do not have insurance for gradual pollution nor do we have coverage for penalties or fines that may be assessed by a governmental authority.

We expect the future availability and cost of insurance to be impacted by the various catastrophic events and large losses that insurers have incurred over the past several years. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums.

We have a risk assessment program that analyzes safety and environmental hazards 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.

We are a member in Oil Insurance Limited (OIL). OIL is a mutual insurance company which insures property, pollution liability, control of well and other catastrophic risks. See Contractual Obligations below for a discussion of our theoretical withdrawal premium liability.

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. See Items 1. and 2. Business and Properties – Oil Spill Response Preparedness.

Financing Activities

Long-Term Debt Our long-term debt totaled $7.6 billion (excluding capital lease and other obligations) at December 31, 2015, with maturities ranging from 2019 to 2097.

Debt Refinancing On January 6, 2016, we announced a series of transactions, consisting of a new term loan (New Term Loan) and cash tender offers for certain outstanding notes, which we expect will collectively enhance our financial flexibility and result in future interest expense savings. The New Term Loan is a three-year agreement, due January 6, 2019, with seven lending institutions for a principal amount of up to $1.4 billion. Provisions of the New Term Loan agreement, including pricing and covenants, are consistent with those contained in our existing Credit Facility. Borrowings under the New Term Loan agreement may be pre-paid in full or in part at any time prior to its maturity without premium.

In connection with the New Term Loan commitments, we simultaneously launched cash tender offers for the following series of our notes: 5.875% Senior Notes due 2024, 5.875% Senior Notes due 2022 and 5.625% Senior Notes due 2021, all of which were originally assumed as part of the Rosetta Merger. The maximum aggregate purchase price (exclusive of accrued interest) of the notes to be purchased, plus fees, was limited to $1.4 billion and funded by borrowings under the New Term Loan. We are currently evaluating the accounting for the tendered notes to determine the impact, if any, it may have on our financial position and results of operations. The interest rate on the New Term Loan at January 31, 2016 was LIBOR plus 1.25%.

Credit Facility Our principal source of liquidity is our Credit Facility that matures August 27, 2020. During 2015, we entered into the Second Amendment to Credit Agreement (Second Amendment) which, among other things, extended the maturity date of the Credit Facility from October 3, 2018 to August 27, 2020.

Our Credit Facility is available for general corporate purposes and has a commitment of $4.0 billion through the maturity date. Certain lenders that are a party to the Credit Agreement 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.

At December 31, 2015, there were no amounts outstanding under the Credit Facility, leaving the entire $4.0 billion available for use. We may rely on our Credit Facility to help fund our capital investment program and may periodically borrow amounts for working capital purposes. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Public Debt Offerings We occasionally enter into public debt offerings to increase our liquidity. On November 7, 2014, we completed an offering of $650 million senior unsecured 3.90% notes due November 15, 2024 and $850 million senior unsecured 5.05% notes due November 15, 2044. Net proceeds were used to repay outstanding indebtedness under our Credit Facility and for general corporate purposes.

Capital Lease and Other Obligations We occasionally enter into lease agreements for operating assets or corporate buildings that are accounted for as capital leases. Capital leases are included in debt in our consolidated balance sheets. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Fixed-Rate Debt Our outstanding fixed-rate debt (excluding capital lease and other obligations) totaled $7.6 billion at December 31, 2015. The weighted average interest rate on fixed-rate debt was 5.71%, with maturities ranging from 2019 to 2097. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital increased to 43% at December 31, 2015 from 38% at December 31, 2014. Significant changes in our financial position impacting the ratio included the following:

- $1.8 billion net increase in debt;
- $291 million decrease in shareholders' equity from dividends paid; and
- $2.4 billion decrease in shareholders' equity from current year net loss.

Cash Interest Payments We made cash interest payments related to our outstanding debt of $404 million in 2015, $305 million in 2014 and $258 million in 2013.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $8 million in 2015, $48 million in 2014 and $51 million in 2013. Proceeds received from the exercise of stock options fluctuate primarily based on the number of options exercised which is influenced by the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued.

Dividends We paid cash dividends totaling 72 cents per common share in 2015, 68 cents per common share in 2014 and 55 cents per common share in 2013 (as adjusted for the 2-for-1 stock split during second quarter 2013).

On January 26, 2016, the Board of Directors declared a quarterly cash dividend of 10 cents per common share, which represents a reduction of 8 cents from the fourth quarter 2015 dividend, and aligns the dividend yield with historical levels. The dividend will be paid February 22, 2016, to shareholders of record on February 8, 2016.

The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Common Stock Repurchases We receive shares of our common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received approximately 491,000 shares with a total value of $21 million in 2015, 255,000 shares with a total value of $16 million in 2014, and 250,000 shares with a total value of $14 million in 2013.

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, 2015, the material off-balance sheet arrangements and transactions that we have entered into included the CONSOL Carried Cost Obligation, drilling rig contracts, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry.

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

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

CONSOL Carried Cost Obligation We have agreed to fund a portion of CONSOL's future drilling and completion costs (CONSOL Carried Cost Obligation). The remaining obligation totaled approximately $1.6 billion at December 31, 2015, and is expected to extend over a multi-year period. It is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are at or above $4.00 per MMBtu for three consecutive months.

The CONSOL Carried Cost Obligation was suspended from the end of 2011 until February 28, 2014 due to low natural gas prices. We began funding a portion of CONSOL's working interest share of certain drilling and completion costs as of March 1, 2014; however, the funding was suspended again in November 2014 due to lower natural gas prices. Based on the December 31, 2015 Henry Hub natural gas price curve, we forecast that the CONSOL Carried Cost Obligation will be suspended in 2016.

Other Other than the off-balance sheet arrangements listed above, 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 also Contractual Obligations below.

Contractual Obligations

The following table summarizes certain contractual obligations as of December 31, 2015 that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. The table excludes the CONSOL Carried Cost Obligation noted above as specific payment dates are unknown. Unless otherwise noted, all amounts are net to our interest.

Obligation	Total	2016	2017 and 2018	2019 and 2020	2021 and beyond
(millions)					
Long-Term Debt [1]	$ 7,573	$ —	$ —	$ 1,000	$ 6,573
Interest Payments [2]	6,159	432	865	713	4,149
Capital Lease and Other Obligations [3]	512	76	160	97	179
Drilling and Equipment Obligations [4]	338	195	143	—	—
Purchase Obligations [5]	177	96	46	26	9
Transportation and Gathering [6]	3,170	217	562	575	1,816
Operating Lease Obligations [7]	345	42	83	52	168
Other Liabilities [8]					
Asset Retirement Obligations [9]	988	126	219	115	528
Total Contractual Obligations	$ 19,262	$ 1,184	$ 2,078	$ 2,578	$ 13,422

(1) Long-term debt excludes our capital lease and other obligations. Amounts do not include impact of debt refinancing activities subsequent to year end. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(2) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2015. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(3) Annual capital lease payments, net to our interest, exclude regular maintenance and operational costs. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(4) Drilling and equipment obligations represent our working interest share of contractual agreements with third-party service providers to procure drilling rigs, such as the Atwood Advantage drill ship used in our Gulf of Mexico operations, and other related equipment for exploratory and development drilling activities. See Counterparty Credit Risk, above, and Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(5) Purchase obligations represent our working interest share of contractual agreements to purchase goods or services that are enforceable, are legally binding and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. See Counterparty Credit Risk, above, and Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(6) Transportation and gathering obligations represent minimum charges for firm transportation and gathering agreements related to our production. See Items 1. and 2. Business and Properties – Delivery Commitments. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(7) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. Amounts have not been discounted. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $217 million and accrued benefit costs of $29 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

(9) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data – Note 9. Asset Retirement Obligations.

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 periods of several years, and failure to conduct such exploration activities within the prescribed periods could lead to loss of leases or exploration rights. Our exploration commitments currently include a 3D seismic obligation offshore Gabon.

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

OIL Contingency As of December 31, 2015, we accrued approximately $13 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, 2015.

Letters of Credit In the ordinary course of business, we maintain letters of credit with a variety of banks in support of certain performance obligations of our subsidiaries. Outstanding letters of credit totaled approximately $68 million at December 31, 2015.

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. In addition, there are no existing ratings triggers in any of our commodity hedging agreements that would require the posting of collateral. However, a series of downgrades or other negative rating actions could increase our cost of financing, and may increase our requirements to post collateral as financial assurance of performance under certain other contractual arrangements such as pipeline transportation contracts, crude oil and natural gas sales contracts, work commitments and certain abandonment obligations. A requirement to post collateral could have a negative impact on our liquidity.

Other

Pension Plan In third quarter 2015, we completed the process of terminating our noncontributory, tax-qualified defined benefit pension plan through the purchase of annuities for the remaining participants. As a result, we expensed all remaining unamortized prior service costs and actuarial losses from accumulated other comprehensive loss (AOCL). During 2015, we expensed $88 million related to the pension plan termination. As of December 31, 2015, $13 million, net of tax, related to our restoration plan remains in AOCL.

Income Taxes We made cash payments for income taxes, net of refunds, of $202 million in 2015, $150 million in 2014 and $165 million in 2013.

Contingencies Payments to settle legal proceedings totaled approximately $11 million in 2015, $3 million in 2014 and $21 million in 2013. We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

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 All of the reserves data in this Form 10-K are estimates. Estimates of our crude oil, natural gas and NGL reserves are prepared by our qualified petroleum engineers in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. 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, natural gas and NGLs that are ultimately recovered. In addition, economic producibility of reserves is dependent on the commodity prices used in the reserves estimate. Our reserves estimates are based on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, crude oil and natural gas prices are volatile and, as a result, our reserves estimates will change in the future.

Estimates of proved crude oil, natural gas and NGL 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. 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 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 We account for crude oil and natural gas properties under the successful efforts method of accounting. Under the successful efforts method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find commercial quantities of proved reserves, and drill and equip development wells are capitalized. Proved property acquisition costs are amortized to expense by the unit-of-production method on a field-by-field basis based on total proved crude oil, natural gas and NGL reserves as estimated by our qualified petroleum engineers. Costs to drill and equip exploratory wells that find proved reserves and drill and equip development wells are also amortized to expense by the unit-of-production method on a field-by-field basis. These costs, along with support equipment and facilities, are amortized based on proved developed crude oil, natural gas and NGL reserves. 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. Application of the successful efforts method results in the expensing of certain costs including geological and geophysical costs, exploratory dry holes and delay rentals, during the periods the costs are incurred.

The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the full cost method, 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, under the full cost method, 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. We believe the successful efforts method is the most appropriate method to use in accounting for our crude oil and natural gas properties because it provides a better representation of our results of operations, especially during periods of active exploration. If we had used the full cost method, our financial position and results of operations could have been significantly different.

Exploratory Well Costs In accordance with the successful efforts method of accounting, the costs associated with drilling an exploratory well may be capitalized temporarily, or “suspended,” pending a determination of whether crude oil or natural gas have been discovered and can be estimated with reasonable certainty to be economically producible. We carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion 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 deepwater Gulf of Mexico or international projects, it may take several years 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 and submitting requests for permits and approvals and believe they will be obtained.

Management assesses the status of suspended exploratory well costs on a quarterly basis. These costs may be charged to exploration expense in future periods if we decide not to pursue additional exploratory or development activities. This occurred in 2015 when we elected to discontinue our exploration effort in northeast Nevada after assessing its commercial viability in the current commodity price environment.

At December 31, 2015, the balance of property, plant and equipment included $1.4 billion of suspended exploratory well costs, $1.3 billion of which had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means including additional seismic work, drilling additional appraisal wells to confirm the size of the hydrocarbon deposit, or evaluating the potential commerciality of the exploratory wells. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

Impairment of Proved Oil and Gas Properties and Other Investments We assess proved crude oil and natural gas properties and other investments for possible impairment whenever events or circumstances indicate that the recorded carrying values of the assets may not be recoverable. We recognize an impairment loss as a result of an event that causes us to consider the possibility that impairment may have occurred and when the estimated undiscounted future cash flows from a property or other investment are less than the carrying value. If impairment is indicated, the carrying values are written down to fair value, which, in the absence of comparable market data, is estimated using a discounted cash flow method. In our cash flow method, cash flows are discounted using a risk-adjusted rate and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil, natural gas and NGL reserves and future commodity prices, revenues and operating and development costs. Negative revisions in estimates of reserves quantities or expectations of falling commodity prices or rising operating or development costs could result in a reduction in undiscounted future cash flows and could indicate property impairment.

During 2015, we assessed proved properties for possible impairment due to lower commodity prices, performance issues, and/or changes in our intended use. Certain assets were determined to be impaired and were written down to their estimated fair values under a discounted cash flow model. The discounted cash flow model included management's estimates of future oil and gas production, commodity prices based on forward commodity price curves at the date of the estimate, operating and development costs, and discount rates.

We recorded total pre-tax (non-cash) asset impairment charges of $533 million in 2015, $500 million in 2014 and $86 million in 2013 for proved oil and gas properties and other investments. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Impairment of Unproved Oil and Gas Properties We also perform assessments of individually significant unproved crude oil and natural gas properties for impairment on a quarterly basis and recognize a loss with a charge to exploration expense 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 values to a significant unproved property (probable and/or possible reserves) as the result of a business combination or other purchase of proved and unproved properties, we use a future cash flow analysis to assess the property for impairment. Cash flows used in the impairment analysis are determined based upon management's estimates of probable and possible reserves, future commodity prices, and future costs to produce the reserves. *Probable reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(18) as those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. *Possible reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(17) as those additional reserves that are less certain to be recovered than probable reserves.

Negative revisions in estimated reserves quantities, reductions in commodity prices, or increases in estimated costs could cause a reduction in the value of an unproved property and, therefore, could also cause a reduction in the carrying amount of the property. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the cash flows are discounted using a risk-adjusted rate and compared to the carrying value for determining the amount of the impairment loss to record. The estimated prices used in the cash flow analysis are determined by management based on forward commodity price curves as of the date of the estimate, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors.

Due to the volatility of crude oil, natural gas and NGL prices, these cash flow estimates are inherently imprecise. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political and regulatory climate in areas in which we operate also impact the amounts and timing of impairment provisions.

We assessed the recoverability of our significant unproved oil and gas properties with allocated fair values periodically during 2015, 2014 and 2013. In 2015, we recognized approximately $70 million of exploration expense related to impairment or abandonment of exploration activities.

Purchase Price Allocations We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations, such as the Rosetta Merger in 2015. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a 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.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of crude oil, natural gas and NGL 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 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 risking 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.

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.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment 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 those originally used to determine fair value. 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. See Item 8. Financial Statements and Supplementary Data – Note 3. Merger, Acquisitions and Divestitures.

Goodwill Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. Prior to conducting our annual goodwill test, our consolidated balance sheet included $779 million of goodwill, all of which had been assigned to the US reporting unit. This goodwill related primarily to the excess purchase price over amounts assigned to assets and liabilities from the Rosetta Merger in 2015 and the Patina Merger in 2005. As of December 31, 2015, our goodwill was determined to be fully impaired.

Annual Goodwill Test Policy Our policy is to conduct a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions; industry and market conditions, including commodity prices; cost factors; overall financial performance; segment dispositions and acquisitions; and other relevant entity-specific events.

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

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

The first step of the impairment test requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. If it is necessary to determine the fair value of the US reporting unit, we use a combination of the income approach and the market approach, each equally weighted at 50%.

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

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

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

2015 Goodwill Test During fourth quarter 2015, we conducted a qualitative goodwill impairment assessment, in accordance with our accounting policy, by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions; industry and market conditions, including the current downturn in the oil and gas industry; cost factors that could have a negative effect on earnings and cash flows; overall financial performance; segment dispositions and acquisitions; and other relevant entity-specific events. Our qualitative goodwill impairment assessment included an additional analysis specifically related to the crude oil and natural gas commodity price decline that began during the second half of 2014 and continued through 2015. We identified factors, including continuing declines in commodity prices and the market value of our common stock, indicating that the fair value of our goodwill could have fallen below its book value.

We therefore performed step one of the goodwill impairment test, used to identify potential impairment, as described above, and compared the fair value of the US reporting unit with its carrying amount, including goodwill. Step one indicated that the carrying value of the reporting unit exceeded its fair value, and the US reporting unit goodwill was considered to be impaired. The fair value of the US reporting unit was determined using multiple valuation approaches, including the projected discounted cash flow method. The determination of the projected discounted cash flows depends on estimates about oil and gas reserves, future commodity pricing, operating costs, capital expenditures, discount rate and timing of future net cash flows. The relative market valuation of similar peer companies using market multiples and other observable market data was also considered in determining the fair value of the US reporting unit. These valuation methodologies represent Level 3 fair value measurements as defined by US GAAP.

We subsequently performed step two of the goodwill impairment test, based on a hypothetical purchase price allocation, and determined that goodwill was fully impaired.

Although we based the fair value estimate of the US reporting unit on assumptions we believe to be reasonable, those assumptions are 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.

Disposals When we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount is based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. During 2015, we sold certain non-core onshore US assets. Goodwill allocated to these assets sold totaled $4 million. See Item 8. Financial Statements and Supplementary Data – Note 3. Merger, Acquisitions and Divestitures.

Derivative Instruments and Hedging Activities In order to mitigate the effects of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All commodity derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net receivable position with a fair value of $592 million at December 31, 2015. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income (loss) because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2015, we reported net gain on commodity derivative instruments of $501 million, net of a $508 million non-cash loss.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk and Interest Rate Risk and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities and Note 13. Fair Value Measurements and Disclosures.

Asset Retirement Obligations Our asset retirement obligations (ARO) 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 it is incurred when we have an existing legal obligation associated with the retirement of our oil and gas properties and the obligation can reasonably be estimated. The associated asset retirement cost is capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as: the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. In periods subsequent to initial measurement of the ARO, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Revisions also result in increases or decreases in the carrying cost of the oil and gas asset. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. Asset retirement obligations totaled $989 million at December 31, 2015. See Item 8. Financial Statements and Supplementary Data – Note 9. Asset Retirement Obligations.

Income Tax Expense and Deferred Tax Assets 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. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, 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.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. 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. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. During 2015, repatriation activity allowed us to use all available foreign tax credits, and the deferred tax asset valuation allowance on our foreign tax credit carryover of approximately $60 million was released.

During 2015, we repatriated earnings from certain of our foreign subsidiaries in order to provide funding for our US domestic projects. These repatriated earnings are subject to US federal and state income taxes, but we do not expect to incur significant cash tax on the repatriations due to foreign tax credit usage and current US tax deductions.

Also during 2015, we recorded a deferred tax liability totaling $227 million for the US and foreign tax rate differences for the future additional US tax liability on accumulated undistributed foreign earnings of our foreign subsidiaries. This amount is net of estimated foreign tax credits. Management has considered numerous factors in determining timing and amounts of possible future distribution of these earnings to the parent company and has determined that, based on these factors, the accumulated undistributed earnings should no longer be classified as indefinitely reinvested. These factors include the future operating and capital requirements of both the parent company and the subsidiaries, the impact of the Israel Natural Gas Framework, the current volatile and low commodity price environment, remittance restrictions imposed by foreign governments or financial agreements and tax consequences of the remittance, including possible application of US foreign tax credits and limitations on foreign tax credits that may be imposed by the Internal Revenue Service (IRS) or IRS regulations.

See Item 8. Financial Statements and Supplementary Data – Note 11. Income Taxes.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

At December 31, 2015, we had entered into commodity derivative instruments related to global crude oil and domestic natural gas sales. 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 at December 31, 2015 with a fair value of $592 million. Based on the December 31, 2015 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $10.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative asset by approximately $133 million. A hypothetical price increase of $0.50 per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $28 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

Even with certain hedging arrangements in place to mitigate the effect of commodity price volatility, our 2016 revenue and results of operations will be adversely affected if commodity prices remain at current levels or decline further. In the current commodity price environment, we are unlikely to hedge future revenues at the same level as our previous hedging arrangements. As such, our revenues will be more susceptible to commodity price volatility as our commodity price derivatives settle and are not replaced.

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

Interest Rate Risk

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

At December 31, 2015, we had approximately $7.6 billion (excluding capital lease and other obligations) of long-term debt outstanding. At December 31, 2015, all debt outstanding was fixed-rate debt with a weighted average interest rate of 5.71%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of December 31, 2015, our cash and cash equivalents totaled approximately $1.0 billion, approximately 40% of which was invested in money market funds and short-term investments with major financial institutions. A change in the interest rate applicable to our short term investments would have a de minimis impact on our earnings and cash flows. We currently have no interest rate derivative instruments outstanding. However, we may enter into interest rate derivative instruments in the future if we determine that it is necessary to invest in such instruments in order to mitigate our interest rate risk.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. During 2015, the US dollar gained in value against other currencies. However, 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. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

Net foreign transaction (gains) losses from continuing operations were de minimis for 2015, 2014 and 2013. Foreign transaction (gains) losses are included in other (income) expense, net in the consolidated statements of operations.

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.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. 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, 2015, 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, 2015, based on those criteria. Our assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Rosetta Merger on July 20, 2015. Rosetta's consolidated total assets and total revenues represent approximately 14% of our consolidated total assets at December 31, 2015 and 6% of our consolidated total revenues for the year ended December 31, 2015. We are in the process of integrating Rosetta's and our internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient internal control over financial reporting throughout this integration process.

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, 2015 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three‑year period ended December 31, 2015. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three‑year period ended December 31, 2015, 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), Noble Energy Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 17, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'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 Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 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.

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.

In our opinion, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Noble Energy, Inc. acquired Rosetta Resources Inc. during 2015, and management excluded from its assessment of the effectiveness of Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2015, Rosetta Resources Inc.'s internal control over financial reporting which represented 14% of total assets and 6% of total revenues included in the consolidated financial statements of Noble Energy, Inc. and subsidiaries as of and for the year ended December 31, 2015. Our audit of internal control over financial reporting of Noble Energy, Inc. also excluded an evaluation of the internal control over financial reporting of Rosetta Resources Inc.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated February 17, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 17, 2016

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

	Year Ended December 31, 2015	2014	2013
Revenues			
Oil, Gas and NGL Sales	$ 3,043	$ 4,931	$ 4,809
Income from Equity Method Investees	90	170	206
Total Revenues	3,133	5,101	5,015
Costs and Expenses			
Production Expense	962	947	844
Exploration Expense	488	498	415
Depreciation, Depletion and Amortization	2,131	1,759	1,568
General and Administrative	396	503	433
Asset Impairments	533	500	86
Goodwill Impairment	779	—	—
Other Operating (Income) Expense, Net	316	(24)	13
Total Operating Expenses	5,605	4,183	3,359
Operating Income (Loss)	(2,472)	918	1,656
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	(501)	(976)	133
Interest, Net of Amount Capitalized	263	210	158
Other Non-Operating (Income) Expense, Net	(15)	(26)	21
Total Other (Income) Expense	(253)	(792)	312
Income (Loss) from Continuing Operations Before Income Taxes	(2,219)	1,710	1,344
Income Tax Provision	222	496	437
Income (Loss) from Continuing Operations	(2,441)	1,214	907
Discontinued Operations, Net of Tax	—	—	71
Net Income (Loss)	$ (2,441)	$ 1,214	$ 978
Earnings (Loss) Per Share, Basic			
Income (Loss) from Continuing Operations	$ (6.07)	$ 3.36	$ 2.53
Discontinued Operations, Net of Tax	—	—	0.19
Net Income (Loss)	$ (6.07)	$ 3.36	$ 2.72
Earnings (Loss) Per Share, Diluted			
Income (Loss) from Continuing Operations	$ (6.07)	$ 3.27	$ 2.50
Discontinued Operations, Net of Tax	—	—	0.19
Net Income (Loss)	$ (6.07)	$ 3.27	$ 2.69
Weighted Average Number of Shares Outstanding			
Basic	402	361	359
Diluted	402	367	363

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

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

	Year Ended December 31,		
	2015	2014	2013
Net Income (Loss)	$ (2,441)	$ 1,214	$ 978
Other Items of Comprehensive Income (Loss)			
Net Change in Mutual Fund Investment	(11)	—	—
Less Tax Expense	4	—	—
Net Change in Pension and Other	99	42	(6)
Less Tax (Benefit) Expense	(35)	(15)	2
Other Comprehensive Income (Loss)	57	27	(4)
Comprehensive Income (Loss)	$ (2,384)	$ 1,241	$ 974

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,028	$ 1,183
Accounts Receivable, Net	450	857
Commodity Derivative Assets, Current	582	710
Other Current Assets	216	325
Total Current Assets	2,276	3,075
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	31,220	25,599
Property, Plant and Equipment, Other	858	630
Total Property, Plant and Equipment, Gross	32,078	26,229
Accumulated Depreciation, Depletion and Amortization	(10,778)	(8,086)
Total Property, Plant and Equipment, Net	21,300	18,143
Goodwill	—	620
Other Noncurrent Assets	620	680
Total Assets	$ 24,196	$ 22,518
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,128	$ 1,578
Other Current Liabilities	677	944
Total Current Liabilities	1,805	2,522
Long-Term Debt	7,976	6,068
Deferred Income Taxes, Noncurrent	2,826	2,516
Other Noncurrent Liabilities	1,219	1,087
Total Liabilities	13,826	12,193
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; 1 Billion and 500 Million Shares Authorized; 470 Million and 402 Million Shares Issued, Respectively	5	4
Additional Paid in Capital	6,360	3,624
Accumulated Other Comprehensive Loss	(33)	(90)
Treasury Stock, at Cost; 38 Million Shares	(688)	(671)
Retained Earnings	4,726	7,458
Total Shareholders' Equity	10,370	10,325
Total Liabilities and Shareholders' Equity	$ 24,196	$ 22,518

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

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

	Year Ended December 31,		
	2015	2014	2013
Cash Flows From Operating Activities			
Net Income (Loss)	$ (2,441)	$ 1,214	$ 978
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	2,131	1,759	1,570
Asset Impairments	533	500	86
Goodwill Impairment	779	—	—
Dry Hole Cost	266	226	149
Deferred Income Taxes	117	268	269
(Income) Loss from Equity Method Investees, Net of Dividends	(14)	33	(17)
(Gain) Loss on Commodity Derivative Instruments	(501)	(976)	133
Net Cash Received (Paid) in Settlement of Commodity Derivative Instruments	1,009	29	(2)
(Gain) Loss on Divestitures	—	(73)	(93)
Loss on Fair Value Adjustment to Inventory	20	—	—
Stock Based Compensation	86	87	80
Non-cash Pension Termination Expense	82	—	—
Expiration and Amortization of Unproved Leaseholds	113	43	30
Other Adjustments for Noncash Items Included in Income	11	(16)	45
Changes in Operating Assets and Liabilities, Net of Assets Acquired and Liabilities Assumed			
(Increase) Decrease in Accounts Receivable	453	29	(239)
Increase (Decrease) in Accounts Payable	(364)	318	(87)
Increase (Decrease) in Current Income Taxes Payable	(94)	18	(47)
Increase (Decrease) in Other Current Liabilities	(70)	45	20
Other Operating Assets and Liabilities, Net	(54)	2	62
Net Cash Provided by Operating Activities	2,062	3,506	2,937
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(2,979)	(4,871)	(3,947)
Proceeds from Divestitures	151	321	327
Rosetta Merger	61	—	—
Additions to Equity Method Investments	(104)	(71)	(48)
Distributions from Equity Method Investments	—	156	—
Other	—	—	(7)
Net Cash Used in Investing Activities	(2,871)	(4,465)	(3,675)
Cash Flows From Financing Activities			
Exercise of Stock Options	8	48	51
Excess Tax Benefits from Stock-Based Awards	(1)	19	20
Dividends Paid, Common Stock	(291)	(249)	(198)
Purchase of Treasury Stock	(21)	(16)	(14)
Proceeds from Issuance of Shares of Common Stock to Public, Net of Offering Costs	1,112	—	—
Proceeds from Credit Facilities	—	1,050	900
Repayment of Credit Facilities	(70)	(1,050)	(900)
Proceeds from Issuance of Senior Long-Term Debt, Net	—	1,478	985
Repayment of Senior Notes	(12)	(200)	—
Repayment of Capital Lease Obligation	(67)	(55)	(48)
Repayment of Installment Loan and Other	(4)	—	(328)
Net Cash Provided By Financing Activities	654	1,025	468
Increase (Decrease) in Cash and Cash Equivalents	(155)	66	(270)
Cash and Cash Equivalents at Beginning of Period	1,183	1,117	1,387
Cash and Cash Equivalents at End of Period	$ 1,028	$ 1,183	$ 1,117

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

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

	Common Stock [1]	Additional Paid in Capital [1]	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2012	$ 4	$ 3,302	$ (113)	$ (648)	$ 5,713	$ 8,258
Net Income	—	—	—	—	978	978
Stock-based Compensation	—	80	—	—	—	80
Exercise of Stock Options	—	51	—	—	—	51
Tax Benefits Related to Exercise of Stock Options	—	20	—	—	—	20
Dividends (55 cents per share)	—	—	—	—	(198)	(198)
Changes in Treasury Stock, Net	—	—	—	(14)	—	(14)
Rabbi Trust Shares Sold	—	10	—	3	—	13
Net Change in Pension and Other	—	—	(4)	—	—	(4)
December 31, 2013	$ 4	$ 3,463	$ (117)	$ (659)	$ 6,493	$ 9,184
Net Income	—	—	—	—	1,214	1,214
Stock-based Compensation	—	87	—	—	—	87
Exercise of Stock Options	—	48	—	—	—	48
Tax Benefits Related to Exercise of Stock Options	—	19	—	—	—	19
Dividends (68 cents per share)	—	—	—	—	(249)	(249)
Changes in Treasury Stock, Net	—	—	—	(16)	—	(16)
Rabbi Trust Shares Sold	—	7	—	4	—	11
Net Change in Pension and Other	—	—	27	—	—	27
December 31, 2014	$ 4	$ 3,624	$ (90)	$ (671)	$ 7,458	$ 10,325
Net Loss	—	—	—	—	(2,441)	(2,441)
Rosetta Merger	1	1,528	—	—	—	1,529
Stock-based Compensation	—	86	—	—	—	86
Exercise of Stock Options	—	8	—	—	—	8
Tax Benefits Related to Exercise of Stock Options	—	(1)	—	—	—	(1)
Dividends (72 cents per share)	—	—	—	—	(291)	(291)
Changes in Treasury Stock, Net	—	—	—	(21)	—	(21)
Rabbi Trust Shares Sold	—	3	—	4	—	7
Issuance of Shares of Common Stock to Public, Net of Offering Costs	—	1,112	—	—	—	1,112
Net Change in Pension and Other	—	—	57	—	—	57
December 31, 2015	$ 5	$ 6,360	$ (33)	$ (688)	$ 4,726	$ 10,370

[1] Amounts reflect impact of 2-for-1 stock split which occurred during second quarter 2013.

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 oil and natural gas exploration and production. Our core operating areas are onshore US (DJ Basin, Marcellus Shale, Eagle Ford Shale, and Permian Basin), deepwater Gulf of Mexico, offshore Eastern Mediterranean and offshore West Africa.

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to US GAAP. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. 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. See Note 7. Equity Method Investments. All significant intercompany balances and transactions have been eliminated upon consolidation.

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, natural gas and NGL reserves are the most significant of our estimates. All the reserves data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil, natural gas and NGLs 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 and asset retirement obligations, 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. Further 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. See Supplemental Oil and Gas Information (Unaudited).

Reclassification Certain reclassifications have been made to the 2014 and 2013 consolidated financial statements to conform to the 2015 presentation. These reclassifications were not material to the financial statements.

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 13. 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.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other 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.

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 average cost or market. The cost of crude oil inventory includes production costs and 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:

Successful Efforts Method 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, natural gas and NGL reserves on a field-by-field basis, as estimated by our qualified petroleum engineers. Our policy is to use quarter-end reserves and add back current period production to compute quarterly DD&A expense. 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. Repairs and maintenance are expensed as incurred.

Proved Property Impairment We review individually significant proved oil and gas properties and other long-lived assets for impairment at least semi-annually, at year-end and mid-year, or quarterly when events and circumstances indicate a decline in the recoverability of the carrying values of such properties, such as a negative revision of reserves estimates or sustained decrease in commodity prices. We estimate future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amount of a property exceeds its estimated undiscounted future 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 proved property impairment charges in 2015, 2014, and 2013. It is likely that other proved oil and gas properties could become impaired in the future due to commodity price declines and/or field performance. See Note 5. Asset Impairments.

Unproved Property Impairment Our unproved properties consist of leasehold costs and allocated value to probable and possible reserves 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, natural gas and NGL 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. Other individually insignificant unproved properties are amortized on a composite method based on our experience of successful drilling and average holding period. It is reasonably possible that unproved oil and gas properties could become impaired in the future if commodity prices decline. See Note 5. Asset Impairments.

Properties Acquired in Business Combinations When sufficient market data is not available, we determine the fair values of proved and unproved properties acquired in transactions accounted for as business combinations by preparing our own estimates of cash flows from the production of crude oil, natural gas and NGL 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. To compensate for the inherent risk of estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Assets Held for Sale We occasionally market non-core oil and gas properties. At the end of each reporting period, we evaluate our 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 in our consolidated balance sheets. See Note 3. Merger, Acquisitions and Divestitures.

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 deepwater Gulf of Mexico or 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 and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 6. Capitalized Exploratory Well Costs.

Other Property Other property includes automobiles, trucks, airplanes, office furniture, computer equipment and other fixed assets such as buildings and leasehold improvements. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from 3 to 30 years.

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 rate we pay on long-term debt, including our unsecured revolving credit facility (Credit Facility) and bonds. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $144 million in 2015, $116 million in 2014, and $121 million in 2013.

Asset Retirement Obligations Asset retirement obligations 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 it is incurred when we have an existing legal obligation associated with the retirement of our oil and gas properties that can reasonably be estimated, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The asset retirement cost is recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement 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 and included in our DD&A expense in the statement 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 9. Asset Retirement Obligations.

Goodwill Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is subject to annual impairment testing in December (or more frequently as circumstances dictate). Noble has allocated goodwill to the US reporting unit. As of December 31, 2015, our goodwill was fully impaired. See Note 4. Goodwill.

Derivative Instruments and Hedging Activities All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in our consolidated balance sheets as either an asset or liability and 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 includes the non-cash portion of gain and loss on commodity derivative instruments, which represented 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 and 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 arrangement with netting clauses.

Stock-Based Compensation Stock options and other stock-based compensation issued to employees and directors are recorded at grant-date 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. See Note 12. Stock-Based and Other Compensation Plans.

Pension and Other Postretirement Benefit Plans We recognize the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of our defined benefit pension, restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to AOCL, net of tax. The amount remaining in AOCL at December 31, 2015 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. In third quarter 2015, we completed the process of terminating our noncontributory, tax-qualified defined benefit pension plan through the purchase of annuities for the remaining participants. As a result, we reclassified all remaining unamortized prior service cost and actuarial losses relating to the pension plan from AOCL to earnings. See Note 12. Stock-Based and Other Compensation Plans.

Income Taxes Income taxes are accounted for under 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.

In addition, we provide a deferred tax liability for the US and foreign tax rate differences for the future additional US tax liability on accumulated undistributed foreign earnings of our foreign subsidiaries, net of estimated foreign tax credits. See Note 11. 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 and Imbalances We record revenues from the sales of crude oil, natural gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlements method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued.

Basic and Diluted Earnings (Loss) Per Share 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.

On April 22, 2013, Noble Energy's Board of Directors approved a 2-for-1 split of its common stock to be effected in the form of a stock dividend. The stock dividend was distributed on May 28, 2013 to shareholders of record as of May 14, 2013. Earnings per share and common shares outstanding are reported giving retrospective effect to the common stock split. See Note 14. Earnings (Loss) Per Share.

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 18. 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.

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.

Segment Information Accounting policies for geographical segments are the same as those described above. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments. See Note 15. Segment Information.

Changes in Shareholders' Equity On April 28, 2015, our shareholders voted to approve an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares of our common stock from 500 million to 1 billion shares.

Recently Issued Accounting Standards

Income Taxes In November 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2015-17 (ASU 2015-17): *Income Taxes (Topic 940)*, effective for annual and interim reporting periods beginning after December 15, 2016, with early adoption permitted. ASU 2015-17 requires that all deferred tax liabilities and assets, as well as any related valuation allowance, be classified in the balance sheet as noncurrent. This guidance may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We elected to early adopt ASU 2015-17 as of December 31, 2015 with prospective application. See Note 10. Income Taxes.

Business Combinations In September 2015, the FASB issued Accounting Standards Update No. 2015-16 (ASU 2015-16): Business Combinations (Topic 805), effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period, to simplify the accounting for measurement-period adjustments for an acquirer in a business combination. ASU 2015-16 requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The acquirer is required to adjust its financial statements for the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts calculated as if the accounting had been completed at the acquisition date. We are currently evaluating the provisions of ASU 2015-16 and assessing the impact, if any, it may have on our financial position and results of operations.

Inventory In July 2015, the FASB issued Accounting Standards Update No. 2015-11 (ASU 2015-11): *Simplifying the Measurement of Inventory*, effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We follow the average cost method and are currently evaluating the provisions of ASU 2015-11 and assessing the impact, if any, it may have on our financial position and results of operations.

Debt Issuance Costs In April 2015, the FASB issued Accounting Standards Update No. 2015-03 (ASU 2015-03): *Simplifying the Presentation of Debt Issuance Costs*, effective for annual and interim periods beginning after December 15, 2015. ASU 2015-03 requires that all costs incurred to issue debt be presented in the balance sheet as a direct deduction from the carrying value of the debt. It is effective retrospectively for all prior periods presented in the financial statements beginning in first quarter 2016 and is only expected to impact the presentation of our consolidated balance sheet. In August 2015, the FASB issued ASU 2015-15 to specifically address the presentation and subsequent measurement of debt issuance costs related to line-of-credit arrangements. ASU 2015-15 allows entities to defer and present debt issuance costs related to line-of-credit arrangements as an asset and amortize the costs ratably over the term of the line-of-credit arrangement. We elected to early adopt ASU 2015-03 as of December 31, 2015 and have applied the new guidance to debt issuance costs related to our senior notes. Debt issuance costs related to our Credit Facility will continue to be presented as an asset and amortized over the term of the Credit Facility. As of December 31, 2015 and 2014, we had $12 million and $15 million of capitalized, unamortized debt issuance costs, respectively, related to our Credit Facility included in other noncurrent assets in our consolidated balance sheet. See Note 10. Long-Term Debt.

Consolidation In February 2015, the FASB issued Accounting Standards Update No. 2015-02 (ASU 2015-02): *Consolidation - Amendments to the Consolidation Analysis*, effective for annual and interim periods beginning after December 15, 2015. ASU 2015-02 changes the guidance as to whether an entity is a variable interest entity (VIE) or a voting interest entity and how related parties are considered in the VIE model. We are currently evaluating the provisions of ASU 2015-02 and assessing the impact, if any, it may have on our financial position and results of operations.

Revenue Recognition In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, Revenue from Contracts with Customers, and supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, ASU 2014-09 supersedes the cost guidance in Subtopic 605-35, Revenue Recognition - Construction-Type and Production-Type Contracts, and creates new Subtopic 340-40, Other Assets and Deferred Costs - Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. Initially, the amendments in ASU 2014-09 were effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and early application was not permitted. In August 2015, the FASB agreed to give companies an extra year to comply with the new standard through the issuance of ASU 2015-14. The standard will be effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. We are currently evaluating the provisions of ASU 2014-09 and implementation guidance to determine the impact, if any, it may have on our financial position and results of operations.

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Production Expense			
Lease Operating Expense	$ 563	$ 593	$ 524
Production and Ad Valorem Taxes	127	184	188
Transportation Expense	272	170	132
Total	$ 962	$ 947	$ 844
Other Operating Expense, Net			
Midstream Gathering and Processing (Income) Expense, Net	$ 9	$ 11	$ 6
Corporate Restructuring Expense (1)	51	—	—
Stacked Drilling Rig Expense (2)	30	—	—
Pension Plan Expense(3)	88	—	—
Rosetta Merger Expense(4)	81	—	—
(Gain) Loss on Divestitures	—	(73)	(36)
Inventory Adjustment (5)	20	—	—
Other, Net	37	38	43
Total	$ 316	$ (24)	$ 13
Other Non-Operating (Income) Expense, Net			
Deferred Compensation (Income) Expense (6)	$ (12)	$ (25)	$ 26
Other (Income) Expense, Net	(3)	(1)	(5)
Total	$ (15)	$ (26)	$ 21

(1) Amount represents expenses associated with the relocation of our Ardmore, Oklahoma office to our corporate headquarters in Houston and other organizational activities.
(2) Amount represents the day rate cost associated with drilling rigs under contract, but not currently being utilized in our US onshore drilling programs.
(3) Amount includes reclassification of the actuarial loss from AOCL related to the re-measurement and termination of our defined benefit pension plan to net income (loss).
(4) Amount represents expenses associated with the completion of the Rosetta Merger. See Note 3. Merger, Acquisitions and Divestitures.
(5) Amount represents lower of cost or market adjustment to materials and supplies inventory. See Note 13. Fair Value Measurements.
(6) Amounts represent increases (decreases) in the fair values of shares of our common stock held in a rabbi trust and mutual funds.

Additional balance sheet information is as follows:

	December 31,	
(millions)	2015	2014
Accounts Receivable, Net		
Commodity Sales	$ 298	$ 405
Joint Interest Billings	20	297
Other	151	171
Allowance for Doubtful Accounts	(19)	(16)
Total	$ 450	$ 857
Other Current Assets		
Inventories, Materials and Supplies	$ 92	$ 81
Inventories, Crude Oil	23	24
Assets Held for Sale[1]	67	180
Prepaid Expenses and Other Assets, Current	34	40
Total	$ 216	$ 325
Other Noncurrent Assets		
Equity Method Investments	$ 453	$ 325
Mutual Fund Investments	90	111
Commodity Derivative Assets, Noncurrent	10	180
Other Assets, Noncurrent	67	64
Total	$ 620	$ 680
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 166	$ 110
Income Taxes Payable	86	180
Deferred Income Taxes, Current	—	158
Asset Retirement Obligations, Current	128	81
Accrued Benefit Costs, Current	3	125
Interest Payable	83	70
Current Portion of Capital Lease and Other Obligations	53	68
Other Liabilities, Current	158	152
Total	$ 677	$ 944
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 217	$ 218
Asset Retirement Obligations, Noncurrent	861	670
Accrued Benefit Costs, Noncurrent	25	24
Other Liabilities, Noncurrent	116	175
Total	$ 1,219	$ 1,087

[1] Assets held for sale at December 31, 2015 include the Karish and Tanin natural gas discoveries, offshore Israel.

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 260	$ 189	$ 137
Income Taxes Paid, Net	202	150	165
Non-Cash Financing and Investing Activities			
Increase in Capital Lease and Other Obligations	55	110	96

Note 3. Merger, Acquisitions and Divestitures

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

Allocation of Purchase Price The merger has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Rosetta to the assets acquired and the liabilities assumed based on the fair value at the merger date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-merger contingencies, final tax returns that provide the underlying tax basis of Rosetta's assets and liabilities, and final appraisals of assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period following the merger date, in line with the acquisition method of accounting, during which time the value of the assets and liabilities may be revised as appropriate.

The following table sets forth our preliminary purchase price allocation which was based on fair values of assets acquired and liabilities assumed at the merger date, July 20, 2015, with the excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill:

		(in millions, except stock price)
Shares of Noble Energy common stock issued to Rosetta shareholders		41
Noble Energy common stock price on July 20, 2015	$	36.97
Fair value of common stock issued	$	1,518
Plus: fair value of Rosetta's restricted stock awards and performance awards assumed		10
Plus: Rosetta stock options assumed		1
Total purchase price		1,529
Plus: liabilities assumed by Noble Energy		
Accounts Payable		100
Current Liabilities		37
Long-Term Deferred Tax Liability		8
Long-Term Debt		1,992
Other Long Term Liabilities		23
Asset Retirement Obligation		27
Total purchase price plus liabilities assumed	$	3,716
Fair Value of Rosetta Assets		
Cash and Equivalents	$	61
Other Current Assets		76
Derivative Instruments		209
Oil and Gas Properties:		
Proved Properties		1,613
Undeveloped Leaseholds		1,355
Gathering and Processing Assets		207
Asset Retirement Obligation		27
Other Property Plant and Equipment		5
Implied Goodwill [1]		163
Total Asset Value	$	3,716

[1] Goodwill was fully impaired at December 31, 2015. See Note 4. Goodwill.

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the merger and represent Level 2 inputs. Derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs. The long-term debt balance includes amounts outstanding under Rosetta's credit facility which was assumed by Noble and repaid subsequent to the merger in third quarter 2015.

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

The results of operations attributable to Rosetta are included in our consolidated statement of operations beginning on July 21, 2015. Revenues of $181 million and pre-tax net loss of $120 million, inclusive of $163 million goodwill impairment, from Rosetta were generated from July 21, 2015 to December 31, 2015.

Proforma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Rosetta and gives effect to the merger as if it had occurred on January 1, 2014. The below information 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 Rosetta's outstanding shares of common stock and equity awards as of the closing date of the merger, (ii) adjustments to conform Rosetta's historical policy of accounting for its oil and natural gas properties from the full cost method to the successful efforts method of accounting, (iii) depletion of Rosetta's fair-valued proved oil and gas properties, and (iv) the estimated tax impacts of the pro forma adjustments. Additionally, pro forma earnings for the year ended December 31, 2015 were adjusted to exclude $81 million of merger-related costs incurred by Noble Energy and $37 million incurred by Rosetta. The pro forma results of operations do not include any cost savings or other synergies that may result from the Rosetta Merger or any estimated costs that have been or will be incurred by us to integrate the Rosetta assets.

The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Rosetta Merger taken place on January 1, 2014; furthermore, the financial information is not intended to be a projection of future results.

	Year Ended December 31,	
(in millions, except per share amounts)	2015	2014
Revenues	$ 3,428	$ 6,112
Net Income (Loss)	$ (2,393)	$ 1,607
Earnings (Loss) Per Share		
Basic	$ (5.64)	$ 4.01
Diluted	$ (5.64)	$ 3.94

Sale of Non-Core Onshore US Properties During the past three years, we closed the sales of non-core onshore US crude oil and natural gas properties. The information regarding the assets sold is as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Cash Proceeds	$ 151	$ 135	$ 150
Less			
Net Book Value of Assets Sold	(156)	(150)	(117)
Goodwill Allocated to Assets Sold [1]	(4)	(7)	(8)
Asset Retirement Obligations Associated with Assets Sold	8	48	8
Other Closing Adjustments	1	10	3
Gain on Divestitures	$ —	$ 36	$ 36

[1] See Note 4. Goodwill.

China In June 2014, we sold our China assets. We determined the sale of our China assets did not meet the criteria for discontinued operations presentation under ASU 2014-08. The information regarding the China assets sold is as follows:

	Year Ended December 31, 2014
(millions)	2014
Sales Proceeds	$ 186
Less	
Net Book Value of Assets Sold	(149)
Other Closing Adjustments	(2)
Gain on Divestiture	$ 35

Assets Held for Sale In November 2015, we executed an agreement to divest our 47% interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields, for a total transaction value of $73 million ($67 million for asset consideration and $6 million from adjustment of costs). These assets were held for sale as of December 31, 2015, and the transaction closed in January 2016.

DJ Basin Acreage Exchange In October 2013, we closed an acreage exchange agreement with another operator related to our position in the DJ Basin. Each party exchanged approximately 50,000 net acres within the same field. The exchange consolidated our acreage into large contiguous blocks, which has provided the opportunity to optimize drilling, production, and gathering activities and add more extended-reach lateral wells to our development program. In accordance with guidance for oil and gas property conveyances, the transaction was accounted for at net book value, with no gain or loss recognized. We received $105 million in cash related to reimbursement of capital expenditures and other normal closing adjustments from the effective date of January 1, 2013 to closing date, which was recorded as a reduction in the net book value of the field.

North Sea Properties During 2013, we sold additional non-operated, North Sea properties. The 2013 sales resulted in a $65 million gain based on net sales proceeds of $56 million. During 2013, the North Sea geographical segment was presented as discontinued operations in our consolidated statements of operations. However, we were unable to locate purchasers for the remaining properties, and as of January 1, 2014, we no longer considered a sale probable. Therefore, the remaining assets were reclassified to assets held and used. See Note 5. Asset Impairments.

Summarized results of discontinued operations are as follows:

	Year Ended December 31,	
(millions)	2013	
Oil and Gas Sales	$	37
Income Before Income Taxes		12
Income Tax Expense		6
Operating Income, Net of Tax		6
Gain on Sale, Net of Tax		65
Discontinued Operations, Net of Tax	$	71

Note 4. Goodwill

Our goodwill relates primarily to the excess purchase price over amounts assigned to assets and liabilities from the Rosetta Merger in 2015 and the Patina Merger in 2005 and is associated with our US reporting unit. During 2015, goodwill increased $163 million due to the Rosetta Merger and decreased $4 million due to allocations of goodwill to onshore US properties sold.

During 2015, we reviewed our goodwill balance for impairment in accordance with our accounting policy and identified factors, including continuing declines in commodity prices and the market value of our common stock, indicating that the fair value of our goodwill could have fallen below its book value. As of December 31 2015, we determined that our goodwill was fully impaired and recognized a loss of $779 million.

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 supported that the implied fair value of goodwill is zero and, as such, goodwill was fully impaired.

Note 5. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Onshore US	$ —	$ 42	$ 39
Deepwater Gulf of Mexico	158	350	—
Equatorial Guinea	339	—	—
Eastern Mediterranean	36	14	47
North Sea	—	94	—
Total	$ 533	$ 500	$ 86

2015 Asset Impairments During 2015, certain deepwater Gulf of Mexico, Eastern Mediterranean and Equatorial Guinea properties were written down to their estimated fair values using a discounted cash flow model. The cash flow model included management's estimates of future crude oil and natural gas production, commodity prices based on forward commodity price curves or contract prices as of the date of the estimate, operating and development costs, and discount rates. Impairment charges of $481 million resulted from reductions in the forward crude oil prices as of December 31, 2015. In addition, we recorded approximately $47 million of impairment primarily related to revisions in expected field abandonment and other costs for deepwater Gulf of Mexico and Eastern Mediterranean properties.

During fourth quarter 2015, we executed an agreement to divest our interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields. As a result, these assets were written down to expected proceeds less costs to sell, resulting in a $5 million impairment.

2014 Asset Impairments As a result of declining crude oil prices at the end of 2014, we recorded impairment charges of $250 million related to certain onshore US and deepwater Gulf of Mexico properties.

During 2014, South Raton in the deepwater Gulf of Mexico was shut-in due to mechanical issues; therefore, we recorded additional impairment charges of $74 million for South Raton in fourth quarter 2014.

Additionally, the asset carrying values of certain crude oil and natural gas properties in the deepwater Gulf of Mexico and offshore Israel increased when we recorded associated increases in asset retirement obligations. We determined that the recorded carrying values of some of these assets were not recoverable from future cash flows and recorded impairment expense of $51 million.

During third quarter 2014, we reclassified certain non-core properties as assets held for sale. The assets were written down to expected proceeds less costs to sell, resulting in a $31 million impairment.

In March 2014, the operator of the MacCulloch North Sea field notified the working interest owners that expected field abandonment costs would be higher than originally projected, and that field abandonment would occur sooner than anticipated. As a result of this new information, we adjusted the asset retirement obligation to reflect the updated estimate of abandonment costs and timing. We assessed the asset for impairment and determined that it was impaired.

2013 Asset Impairments We recorded impairments of the Mari-B field, due to natural field decline, and certain non-core, onshore US properties upon reclassification to assets held for sale. The Mari-B field was written down to its estimated fair value using a discounted cash flow model, as described above. The fair values of onshore US assets held for sale were based on anticipated sales proceeds less costs to sell.

See Note 13. Fair Value Measurements and Disclosures.

Note 6. 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. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense as dry hole cost.

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

	Year Ended December 31,		
(millions)	2015	2014	2013
Capitalized Exploratory Well Costs, Beginning of Period	$ 1,337	$ 1,301	$ 900
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	123	316	581
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale[1]	(19)	(196)	(177)
Capitalized Exploratory Well Costs Charged to Expense [2]	(88)	(84)	(3)
Capitalized Exploratory Well Costs, End of Period	$ 1,353	$ 1,337	$ 1,301

(1) The 2015 amount relates primarily to onshore US exploration activity.

The 2014 amount relates primarily to the Dantzler well (deepwater Gulf of Mexico), for which we sanctioned a development plan, and the Karish and Tanin wells (offshore Israel), which were reclassified to assets held for sale.

The 2013 amount relates primarily to Gunflint (deepwater Gulf of Mexico), for which we sanctioned a development plan.

(2) The 2015 amount relates primarily to northeast Nevada. After assessing its commercial viability in the current commodity price environment, we elected to discontinue our exploration efforts.

The 2014 amount relates to non-core onshore US exploratory well costs and the Scotia exploratory well (offshore Falkland Islands) which were determined to be non-commercial.

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced, and the number of projects that have been capitalized for a period greater than one year:

	December 31,		
(millions)	2015	2014	2013
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 95	$ 247	$ 568
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	1,258	1,090	733
Balance at End of Period	$ 1,353	$ 1,337	$ 1,301
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	14	13	13

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, 2015:

		Suspended Since			
Country/Project *(millions)*	Total	2013 - 2014	2011 - 2012	2010 & Prior	**Progress**
Deepwater Gulf of Mexico					
Troubadour	49	48	1	—	Evaluating development scenarios for this 2013 natural gas discovery including subsea tieback to existing infrastructure.
Katmai	91	91	—	—	Anticipate drilling an appraisal well in 2016 to test the resource potential of this 2014 crude oil discovery.
Offshore Equatorial Guinea					
Diega (Block O) and Carmen (Block I)	233	135	45	53	Evaluating regional development scenarios for this 2008 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks O and I and are engaged in processing the newly-acquired seismic data.
Carla (Block O)	177	133	44	—	Evaluating regional development scenarios for this 2011 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks O and I and are engaged in processing the newly-acquired seismic data.

Yolanda/Felicita	66	18	4	44	Evaluating regional development plans for these 2007/2008 condensate and natural gas discoveries. Natural gas development teams are working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options and finalize data exchange agreements between the two countries.
Offshore Cameroon					
YoYo	51	6	11	34	Working with the government to assess commercialization of this 2007 condensate and natural gas discovery. A natural gas development team is working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options and finalize a data exchange agreement between the two countries.
Offshore Israel					
Leviathan	191	44	106	41	During 2015, the Government of Israel approved the Natural Gas Framework. We are engaged in natural gas marketing activities both for export and, since the enactment of the Natural Gas Framework, for domestic Israeli customers. We continue to refine our development concepts and are preparing to submit a Plan of Development to the Government of Israel. We also continue to pursue financing arrangements to support development.
Leviathan-1 Deep	80	7	73	—	Well did not reach the target interval; developing future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases. We are working on potential well design and placement.
Dalit	28	5	3	20	Submitted a development plan to the government to develop this 2009 natural gas discovery as a tie-in to existing infrastructure.
Dolphin 1	26	3	23	—	Reviewing regional development scenarios for this 2011 natural gas discovery, including a potential tieback to Leviathan. We have applied to the government for a commerciality ruling.
Offshore Cyprus					
Cyprus	214	140	74	—	During 2015, we submitted a Declaration of Commerciality and a Development Plan to the Government of Cyprus. We continue to work with the Government of Cyprus to obtain approval of the development plan and the subsequent issuance of an Exploitation License. Receiving an Exploitation License will allow us and our partners to perform the necessary engineering and design studies and progress the project to final investment decision.
Other					
Projects less than $20 million	52	41	—	11	Continuing to drill and evaluate wells
Total	$ 1,258	$ 671	$ 384	$ 203	

Note 7. Equity Method Investments

Equity Method Investments Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investees in the consolidated statements of operations. 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. Investments accounted for under the equity method consist primarily of the following:

- 45% interest in Atlantic Methanol Production Company, LLC (AMPCO), which owns and operates a methanol plant and related facilities in Equatorial Guinea;
- 28% interest in Alba Plant LLC (Alba Plant), which owns and operates a liquefied petroleum gas processing plant in Equatorial Guinea;
- 50% interest in CONE Gathering LLC (CONE Gathering), which owns and operates natural gas gathering facilities servicing our joint venture properties in the Marcellus Shale; and
- 32% interest in CONE Midstream Partners, LP (CONE Midstream), which constructs, owns and operates natural gas gathering and other midstream energy assets in support of our Marcellus Shale joint venture activities.

Midstream IPO On September 24, 2014, our equity method investee, CONE Gathering, contributed a significant majority of its existing assets to a newly-formed master limited partnership, CONE Midstream, concurrently with an initial public offering of limited partner units. CONE Gathering subsequently distributed $204 million of offering proceeds to us, which is reflected within cash flows from operating activities ($48 million) and cash flows from investing activities ($156 million) within our consolidated statement of cash flows.

Equity method investments are as follows:

	December 31,	
(millions)	2015	2014
Equity Method Investments		
AMPCO	$ 120	$ 141
Alba Plant	87	82
CONE Investments[1]	214	82
Other	32	20
Total Equity Method Investments	$ 453	$ 325

[1] CONE Investments includes our investments in CONE Midstream and CONE Gathering.

Other At December 31, 2015, consolidated retained earnings included $106 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $8 million higher than the underlying net assets of the investee at December 31, 2015. The difference is related to capitalized interest which is being amortized into earnings over the remaining useful life of the plant.

Summarized, 100% combined financial information for equity method investees is as follows:

	December 31,	
(millions)	2015	2014
Balance Sheet Information		
Current Assets	$ 343	$ 412
Noncurrent Assets	1,418	1,169
Current Liabilities	229	374
Noncurrent Liabilities	108	33

	Year Ended December 31,		
(millions)	2015	2014	2013
Statements of Operations Information			
Operating Revenues	$ 645	$ 1,142	$ 1,256
Operating Expenses	393	405	388
Operating Income	252	737	868
Other (Income) Net	(9)	(9)	(14)
Income Before Income Taxes	261	746	882
Income Tax Provision	46	172	212
Net Income	$ 215	$ 574	$ 670

Note 8. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements. The derivative instruments we use may include variable to fixed price commodity swaps, enhanced swaps, two-way and three-way collars, basis swaps and/or put options.

The fixed price swap and two-way 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 two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way 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.

For put options, we typically pay a premium to the counterparty in exchange for the sale of the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium at the time of settlement. If the index price settles at or above the floor price of the put option, we pay only the put option premium at the time of settlement. We had no outstanding put options as of December 31, 2015.

We also may enter into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing. As of December 31, 2015 we did not have any interest rate derivatives outstanding.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 13. 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. Our commodity derivative instruments are currently with a diversified group of major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. 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.

Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Unsettled Derivative Instruments As of December 31, 2015, we had entered into the following crude oil derivative instruments:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
1H16 (1)	Swaps	NYMEX WTI	17,000	$ 68.50	$ —	$ —	$ —
2H16 (1)	Swaps	NYMEX WTI	12,000	74.47	—	—	—
2H16 (1)	Call Option (2)	NYMEX WTI	5,000	—	—	—	54.16
2016	Swaps	Dated Brent	9,000	97.96	—	—	—
2016	Swaps (3)	(4)	6,000	90.28	—	—	—
2016	Two -Way Collars	NYMEX WTI	1,000	—	—	60.00	70.00
2016	Three-Way Collars	NYMEX WTI	6,000	—	61.00	72.50	86.37
2016	Three-Way Collars	Dated Brent	8,000	—	72.50	86.25	101.79
1H17 (1)	Swaps	NYMEX WTI	3,000	60.12	—	—	—
1H17 (1)	Swaps (5)	Dated Brent	3,000	62.80	—	—	—
2H17 (1)	Call Option (2)	NYMEX WTI	3,000	—	—	—	60.12
2017	Call Option (2)	NYMEX WTI	3,000	—	—	—	57.00
2017	Two-Way Collars	NYMEX WTI	5,000	—	—	40.00	54.00

(1) We traditionally enter into a hedge contract term of one year. For 2016 and 2017 we have entered into various derivative hedging arrangements with a contract term of six months resulting in non-uniform annual volumes and weighted average prices.

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

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

(4) The index for these derivative instruments is NYMEX WTI and Argus LLS indices.

(5) We have entered into certain Dated Brent derivative contracts (swaptions), which give counterparties the option to extend for an additional 6-month period. Options covering a notional volume of 3,000 Bbls/d are exercisable on June 30, 2017. If the counterparties exercise all such options, the notional volume of our existing Dated Brent derivative contracts will increase by 3,000 Bbls/d at an average price of $62.80 per Bbl for each month during the period July 1, 2017 through December 31, 2017.

As of December 31, 2015, we had entered into the following natural gas derivative instruments:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2016	Swaps [1]	NYMEX HH	40,000	$ 3.60	$ —	$ —	$ —
2016	Swaps [2]	Houston Ship Channel	30,000	4.04	—	—	—
2016	Two-Way Collars	NYMEX HH	30,000	—	—	3.00	3.50
2016	Two-Way Collars [2]	Houston Ship Channel	30,000	—	—	3.50	5.60
2016	Three-Way Collars	NYMEX HH	90,000	—	2.83	3.42	3.90

(1) We have entered into certain natural gas derivative contracts (swaptions), which give counterparties the option to extend for an additional 12-month period. Options covering a notional volume of 30,000 MMBtu/d are exercisable on December 22 and 23, 2016. If the counterparties exercise all such options, the notional volume of our existing natural gas derivative contracts will increase by 30,000 MMBtu/d at an average price of $3.50 per MMBtu for each month during the period January 1, 2017 through December 31, 2017.

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

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	December 31, 2015		December 31, 2014		December 31, 2015		December 31, 2014	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)								
Commodity Derivative Instruments	Current Assets	$ 582	Current Assets	$ 710	Current Liabilities	$ —	Current Liabilities	$ —
	Noncurrent Assets	10	Noncurrent Assets	180	Noncurrent Liabilities	—	Noncurrent Liabilities	—
Total		$ 592		$ 890		$ —		$ —

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

	Year Ended December 31,		
(millions)	2015	2014	2013
Cash (Received) Paid in Settlement of Commodity Derivative Instruments			
Crude Oil	$ (844)	$ (34)	$ 52
Natural Gas	(147)	5	(50)
NGLs [1]	(18)	—	—
Total Cash (Received) Paid in Settlement of Commodity Derivative Instruments	(1,009)	(29)	2
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments			
Crude Oil	423	(863)	87
Natural Gas	65	(84)	44
NGLs [1]	20	—	—
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	508	(947)	131
(Gain) Loss on Commodity Derivative Instruments			
Crude Oil	(421)	(897)	139
Natural Gas	(82)	(79)	(6)
NGLs [1]	2	—	—
Total (Gain) Loss on Commodity Derivative Instruments	$ (501)	$ (976)	$ 133

[1] Amounts for NGLs relate to commodity derivative instruments, acquired in the Rosetta Merger, which expired as of December 31, 2015.

Note 9. Asset Retirement Obligations

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

	Year Ended December 31,	
(millions)	2015	2014
Asset Retirement Obligations, Beginning Balance	$ 751	$ 586
Liabilities Incurred	67	75
Liabilities Settled	(38)	(101)
Revision of Estimate	166	155
Accretion Expense	43	36
Asset Retirement Obligations, Ending Balance	$ 989	$ 751

For the year ended December 31, 2015

Liabilities incurred were due to new wells and facilities and included $22 million primarily for onshore US, $16 million for deepwater Gulf of Mexico and $29 million for Rosetta Merger related assets.

We settled liabilities of $23 million for the DJ Basin, $2 million for deepwater Gulf of Mexico and $13 million for the North Sea.

Revisions were primarily due to changes in estimated costs for future abandonment activities and acceleration of timing of abandonment and included $96 million for the DJ Basin, $48 million for Eastern Mediterranean, $35 million for deepwater Gulf of Mexico, and decreases of $10 million for Equatorial Guinea and $3 million for other non-core, onshore US developments.

For the year ended December 31, 2014

Liabilities incurred were due to new wells and facilities and included $20 million for onshore US, $25 million for deepwater Gulf of Mexico, $2 million for Cameroon, and $10 million for Eastern Mediterranean. Additional liabilities of $18 million were incurred for wells in Equatorial Guinea.

We settled liabilities of $33 million for the DJ Basin, $62 million for deepwater Gulf of Mexico, and $28 million for other non-core, onshore US developments and $1 million for China. At December 31, 2013, our non-operated North Sea fields were classified as held for sale, which included the related ARO for these fields. During 2014, the unsold North Sea properties were reclassified as held and used, resulting in an offset of $23 million to the balance of liabilities settled.

Revisions were primarily due to changes in estimated costs for future abandonment activities and acceleration of timing of abandonment and included $33 million for DJ Basin, $29 million for deepwater Gulf of Mexico, $16 million for Equatorial Guinea, $8 million for Eastern Mediterranean, and $69 million related to a non-operated North Sea field.

Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 10. Long-Term Debt

Our debt consists of the following:

	December 31, 2015		December 31, 2014	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Credit Facility, due August 27, 2020	$ —	—	$ —	—
Capital Lease and Other Obligations	403	—	413	—
8.25% Senior Notes, due March 1, 2019	1,000	8.25%	1,000	8.25%
5.625% Senior Notes, due May 1, 2021 [(1)]	693	5.63%	—	—%
4.15% Senior Notes, due December 15, 2021	1,000	4.15%	1,000	4.15%
5.875% Senior Notes, due June 1, 2022 [(1)]	597	5.88%	—	—%
7.25% Senior Notes, due October 15, 2023	100	7.25%	100	7.25%
5.875% Senior Notes, due June 1, 2024 [(1)]	499	5.88%	—	—
3.90% Senior Notes, due November 15, 2024	650	3.90%	650	3.90%
8.00% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
6.00% Senior Notes, due March 1, 2041	850	6.00%	850	6.00%
5.25% Senior Notes, due November 15, 2043	1,000	5.25%	1,000	5.25%
5.05% Senior Notes, due November 15, 2044	850	5.05%	850	5.05%
7.25% Senior Debentures, due August 1, 2097	84	7.25%	84	7.25%
Total	$ 7,976		$ 6,197	
Unamortized Discount	(24)		(26)	
Unamortized Premium [(2)]	113		—	
Unamortized Debt Issuance Costs	(36)		(35)	
Total Debt, Net of Discount	$ 8,029		$ 6,136	
Less Amounts Due Within One Year				
Capital Lease and Other Obligations	(53)		(68)	
Long-Term Debt Due After One Year	$ 7,976		$ 6,068	

(1) Represents senior notes assumed in the Rosetta Merger. See Note 3. Merger, Acquisitions and Divestitures.
(2) Debt premium is attributable to senior notes assumed in the Rosetta Merger.

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. Debt issuance costs of approximately $12 million related to our Credit Facility remain and are being amortized to expense over the life of the Credit Facility.

Credit Facility On August 27, 2015, we amended our $4.0 billion Credit Facility to extend the maturity date to August 27, 2020. We periodically borrow amounts for working capital purposes.

Our 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) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (iii) 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.

The Credit Agreement requires that our total debt to capitalization ratio (as defined in the Credit Agreement), 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 Credit Facility and require the immediate repayment of any outstanding advances under the Credit Facility. As of December 31, 2015, we were in compliance with our debt covenants.

The Credit Facility is available for general corporate purposes. Certain lenders that are a party to the Credit Agreement 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.

Debt Exchange On July 29, 2015, we completed our debt exchange offers to exchange all validly tendered and accepted senior notes assumed in the Rosetta Merger. We were able to exchange 99.4% of the outstanding Rosetta senior notes, whereby we issued (i) $693 million senior unsecured 5.625% notes due May 1, 2021, (ii) $597 million senior unsecured 5.875% notes due June 1, 2022 and (iii) $499 million senior unsecured 5.875% notes due June 1, 2024. We incurred financing costs of $12 million related to the debt exchange. We also repaid the balance outstanding under, and terminated, Rosetta's credit facility of $70 million.

2014 Debt Offering On November 7, 2014, we closed an offering of $650 million senior unsecured 3.90% notes due November 15, 2024 and $850 million senior unsecured 5.05% notes due November 15, 2044, receiving aggregate net proceeds of almost $1.5 billion. Both notes pay interest semiannually. Approximately $1.1 billion of the net proceeds were used to repay outstanding indebtedness under our Credit Facility and the balance of the proceeds has been used for general corporate purposes.

Capital Lease and Other Obligations The amounts of the capital lease obligations are based on the discounted present value of future minimum lease payments, and therefore do not reflect future cash lease payments. Amounts due within one year equal the amount by which the capital lease obligations are expected to be reduced during the next 12 months. See Note 18. Commitments and Contingencies for future capital lease payments.

Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments, are as follows:

(millions)	Debt Principal Payments
December 31, 2015	
2016	$ —
2017	—
2018	—
2019	1,000
2020	—
Thereafter	6,573
Total	$ 7,573

Subsequent Event On January 6, 2016, we entered into a term loan agreement with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of up to $1.4 billion. Provisions of the term loan are consistent with those in the Credit Facility. Borrowings under the term loan agreement may be prepaid prior to maturity without premium. In connection with the term loan, we launched cash tender offers for the 5.875% Senior Notes due June 1, 2024, 5.875% Senior Notes due June 1, 2022 and 5.625% Senior Notes due May 1, 2021, all of which were assumed as part of the Rosetta Merger. The borrowings under the term loan will be used solely to fund the tender offers. As of January 21, 2016, approximately $1.38 billion of notes had been validly tendered and accepted by the Company, with a corresponding amount borrowed under the new term loan. We are currently evaluating the accounting for the tendered notes to determine the impact, if any, it may have on our financial position and results of operations.

Note 11. Income Taxes

Components of income (loss) from continuing operations before income taxes are as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Domestic	$ (2,338)	$ 282	$ 202
Foreign	119	1,428	1,142
Total	$ (2,219)	$ 1,710	$ 1,344

The income tax provision from continuing operations consists of the following:

	Year Ended December 31,		
(millions)	2015	2014	2013
Current Taxes			
Federal	$ (1)	$ 19	$ 21
State	—	1	1
Foreign	107	208	144
Total Current	106	228	166
Deferred Taxes			
Federal	216	237	96
State	(5)	13	1
Foreign	(95)	18	174
Total Deferred	116	268	271
Total Income Tax Provision	$ 222	$ 496	$ 437
Effective Tax Rate	(10.0)%	29.0%	32.5%

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
(percentages)	2015	2014	2013
Federal Statutory Rate	35.0 %	35.0%	35.0%
Effect of			
Earnings of Equity Method Investees	0.6	(3.3)	(5.3)
State Taxes, Net of Federal Benefit	0.3	0.8	0.1
Difference Between US and Foreign Rates	2.6	(14.2)	(6.3)
Foreign Exploration Loss	2.7	—	2.7
Change in Valuation Allowance	—	1.9	3.8
Oil Profits Tax - Israel	0.1	0.2	0.3
Tax Contingency	0.4	0.1	0.4
Accumulated Undistributed Foreign Earnings	(37.7)	8.2	—
Goodwill Impairment	(12.3)	—	—
Other, Net	(1.7)	0.3	1.8
Effective Rate	(10.0)%	29.0%	32.5%

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(millions)	2015	2014
Deferred Tax Assets		
Loss Carryforwards	$ 468	$ 170
Employee Compensation and Benefits	151	149
Foreign Tax Credits	—	67
Other	81	51
Total Deferred Tax Assets	$ 700	$ 437
Valuation Allowance - Foreign Loss Carryforwards	(206)	(145)
Valuation Allowance - Foreign Tax Credits	—	(67)
Valuation Allowance - Capital Loss Carryforwards	—	(1)
Net Deferred Tax Assets	$ 494	$ 224
Deferred Tax Liabilities		
Mark to Market of Commodity Derivative Instruments	(128)	(209)
Accumulated Undistributed Foreign Earnings	(368)	(141)
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,824)	(2,548)
Total Deferred Tax Liability	$ (3,320)	$ (2,898)
Net Deferred Tax Liability	$ (2,826)	$ (2,674)

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(millions)	2015	2014
Deferred Income Tax Liability - Current [1]	$ —	$ (158)
Deferred Income Tax Liability - Noncurrent [1]	(2,826)	(2,516)
Net Deferred Tax Liability	$ (2,826)	$ (2,674)

[1] As discussed in Note 1. Summary of Significant Accounting Policies, we have elected to early adopt and apply the presentation requirements of ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*, as of December 31, 2015. Prior periods have not been retrospectively adjusted.

Deferred Tax Assets 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, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2015. 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.

The valuation allowance on the deferred tax assets associated with foreign loss carryforwards totaled $206 million in 2015 and $145 million in 2014. The changes to the valuation allowance for the loss carryforwards between periods were attributable to changes in losses on projects in new venture activities which are not yet commercial.

During 2015, as a result of cash repatriation, we released a valuation allowance of $60 million on our foreign tax credits.

During fourth quarter 2014, fluctuations in crude oil and natural gas prices resulted in an inability to determine whether we would be able to utilize all of our foreign tax credits in the future. Therefore, we set up a deferred tax liability of $141 million on our accumulated undistributed foreign earnings and a corresponding valuation allowance of $36 million on our foreign tax credits.

Rosetta Merger On July 20, 2015, we completed the Rosetta Merger. For federal income tax purposes, the merger qualified as a tax free merger and we acquired carryover tax basis in Rosetta's assets and liabilities. Rosetta had a net deferred tax asset resulting from its federal net operating loss (NOL) estimated at $681 million through the date of acquisition. The merger resulted in a change of control for federal income tax purposes, and the NOL's usage will be subject to an annual limitation in part based on Rosetta's value at the date of the merger. We anticipate full utilization of the total NOL prior to its expiration.

Accumulated Undistributed Earnings of Foreign Subsidiaries Our foreign subsidiaries' undistributed earnings of approximately $1.6 billion at December 31, 2015 are no longer considered to be indefinitely reinvested outside the United States and, accordingly, we recorded$227 million in deferred income taxes in 2015, net of estimated foreign tax credits. We based our change in the indefinite reinvestment assertion on the continued and prolonged decline in global commodity prices and an evaluation of our operations' anticipated capital requirements and projected foreign cash positions given the adoption of the Israel Natural Gas Framework in December 2015. The actual tax impact upon distribution would depend on our tax positions at the time of repatriation and could be significantly different from this estimate.

Effective Tax Rate Our effective tax rate decreased in 2015 as compared with 2014 primarily due to a shift from pre-tax earnings in 2014 to a pre-tax loss in 2015 and the removal of our permanent reinvestment assertion discussed above. In the case of a pre-tax loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective tax rate. Unfavorable permanent differences, such as non-deductible goodwill impairment expense, have the effect of decreasing the tax benefit which, in turn, decreases the effective tax rate. The decrease in the effective tax rate was partially offset by a release of the valuation allowance on foreign tax credits due to usage and losses from funding foreign exploration projects.

Our effective tax rate decreased in 2014 as compared with 2013 primarily due to our ability to benefit from previously unrecognized foreign tax credits, increased earnings in our foreign jurisdictions with rates that vary from the US statutory rate, and a decrease in our Israeli oil profits tax, offset by a change in our state tax estimates and foreign dividend repatriation.

Changes in Israeli Tax Law In July 2013, the Israeli government increased the corporate income tax rate from 25% to 26.5%, effective January 2014. The change increased the deferred tax expense for 2013 by $12 million, which is reported in other, net within our effective rate reconciliation above.

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 routinely made in the financial statements for differences between positions taken in tax returns and amounts recognized in the financial statements in anticipation of the results of these audits.

In our major tax jurisdictions, the earliest years remaining open to examination are: US - 2012, Equatorial Guinea - 2010 and Israel - 2011.

Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense.

A reconciliation of our beginning and ending amounts of unrecognized tax benefits follows:

(millions)	Twelve Months Ended December 31, 2015	
Unrecognized Tax Benefits, Beginning Balance	$	29
Additions for Tax Positions Related to Current Year		—
Additions for Tax Positions of Prior Years		3
Reductions for Tax Positions of Prior Years		(4)
Settlements		(20)
Unrecognized Tax Benefits, Ending Balance	$	8

As of December 31, 2015, approximately $8 million of unrecognized tax benefits would impact our effective tax rate if recognized. The changes to our unrecognized tax benefits during 2015 primarily resulted from changes in various foreign tax return filings, positions and audit settlements. The adjustments to our reserves for uncertain tax positions had a de minimis impact on our net income.

During 2015, we recognized and accrued a de minimis amount of interest and none in penalties.

As of December 31, 2014, approximately $29 million of unrecognized tax benefits would impact our effective tax rate if recognized. The changes to our unrecognized tax benefits during 2014 primarily resulted from changes in various foreign tax return filings and positions. The adjustments to our reserves for uncertain tax positions had a de minimis impact on our net income.

During 2014, we recognized and accrued a de minimis amount of interest and none in penalties.

We expect that our unrecognized tax benefits could continue to change due to the settlement of audits and the expiration of statutes of limitation in the next twelve months; however, we do not anticipate any such change to have a significant impact on our results of operations, financial position or cash flows in the next twelve months.

Note 12. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
(millions)	2015	2014	2013
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 50	$ 63	$ 58
Exploration Expense and Other	36	24	22
Total Stock-Based Compensation Expense	$ 86	$ 87	$ 80
Tax Benefit Recognized	$ (30)	$ (31)	$ (28)

Stock Option and Restricted Stock Plans Our stock option and restricted stock plans are described below.

1992 Stock Option and Restricted Stock Plan Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the 1992 Plan), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) may grant stock options and stock appreciation rights and award restricted stock and cash awards to our officers or other employees and those of our subsidiaries. The maximum number of shares that may be granted under the 1992 Plan is 77,400,000 shares of common stock. At December 31, 2015, 35,850,503 shares of our common stock were reserved for issuance, including 16,019,550 shares available for future grants and awards, under the 1992 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 1992 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. During the period during which such restrictions apply, unless specifically provided otherwise in accordance with the terms of the 1992 Plan, the recipient of restricted stock would be the record owner of the shares and have all the rights of a stockholder 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. Restricted stock awards with a time-vested restriction vest over a three year period (20% after year one, an additional 30% after year two and the remaining 50% after year three) or over a two year period (40% after year one and the remaining 60% after year two). Restricted stock awards with a performance-vested restriction 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, 2015, 705,615 shares of our common stock were reserved for issuance including 693,665 shares available for future grants and awards, under the 2015 Plan.

2005 Stock Plan for Non-Employee Directors The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc., as amended (the 2005 Plan) provides for grants of stock options and awards of restricted stock to our non-employee directors. The 2005 Plan superseded and replaced the 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc. The total number of shares of our common stock that may be issued under the 2005 Plan is 1,600,000. At December 31, 2015, 469,597 shares of our common stock were reserved for issuance.

Prior to March 17, 2011, the 2005 Plan provided for the automatic granting to a non-employee director of up to a maximum of 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (with the February 1 annual and the discretionary grants made to a non-employee director during any calendar year being limited to a combined maximum of 11,200 options). The 2005 Plan was amended so that no automatic option grants would be made under the 2005 Plan on or after March 17, 2011. Discretionary grants by the Board of Directors continue to be permitted under the 2005 Plan (with the grants made to a non-employee director during any calendar year being limited to a maximum of 22,400). Options are issued with an exercise price equal to the market price of our common stock on the date of grant and may be exercised one year after the date of grant. Unless granted by the Board of Directors for a shorter term, the options expire 10 years from the date of grant.

Prior to March 17, 2011, the 2005 Plan also provided for the awarding to a non-employee director of up to a maximum of 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock per non-employee director on February 1 of each year, and discretionary awards by the Board of Directors (with the February 1 annual and the discretionary awards made to a non-employee director during any calendar year being limited to a combined maximum of 4,800 shares of restricted stock). The 2005 Plan was amended so that no automatic grants of restricted stock awards would be made under the 2005 Plan on or after March 17, 2011. Discretionary grants by the Board of Directors continue to be permitted under the 2005 Plan (with the grants made to a non-employee director during any calendar year limited to a maximum of 9,600). Restricted stock is restricted for a period of at least one year from the date of award.

1988 Nonqualified Stock Option Plan for Non-Employee Directors The 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc., as amended, (the 1988 Plan) provided for the issuance of stock options to our non-employee directors. Options issued under the 1988 Plan may be exercised one year after grant and expire 10 years from the grant date. The 1988 Plan provided for the granting of a fixed number of stock options to each non-employee director annually (20,000 stock options for the first calendar year of service and 10,000 stock options for each year thereafter) on February 1 of each year. The 1988 Plan was terminated in 2005, and no additional options can be granted thereunder.

Stock Option Grants The fair value of each stock option granted was 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)	2015	2014	2013
Expected Term (in Years)	6.0	5.9	5.7
Expected Volatility	32.6%	35.1%	36.4%
Risk-Free Rate	1.4%	1.8%	1.1%
Expected Dividend Yield	1.2%	1.1%	1.2%
Weighted Average Grant-Date Fair Value	$ 13.93	$ 20.31	$ 17.08

Stock option activity was as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2014	13,008,322	$ 43.98		
Granted	2,714,185	47.25		
Exercised	(343,145)	23.35		
Forfeited	(808,350)	52.24		
Outstanding at December 31, 2015	14,571,012	$ 44.59	5.6	$ 21
Exercisable at December 31, 2015	10,659,799	$ 41.53	4.5	$ 21

The total intrinsic value of options exercised was $7 million in 2015, $58 million in 2014, and $64 million in 2013.

As of December 31, 2015, $34 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 1.3 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 values of market based restricted stock awards are estimated on the date of award using a Monte Carlo valuation model that uses the assumptions in the following table. The Monte Carlo 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 U.S. 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,	
	2015	2014
Number of Simulations	500,000	500,000
Expected Volatility	30%	30%
Risk-Free Rate	0.8%	0.7%

Restricted stock activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Shares	Weighted Average Award Date Fair Value	Number of Shares	Weighted Average Award Date Fair Value
		(per share)		(per share)
Outstanding at December 31, 2014	1,048,800	$ 55.68	1,518,336	$ 29.10
Awarded	1,554,002	39.57	762,786	27.30
Vested	(1,464,374)	46.57	(1,172)	42.21
Forfeited	(118,958)	51.36	(350,028)	28.41
Outstanding at December 31, 2015	1,019,470	$ 45.55	1,929,922	$ 28.50

The total fair value of restricted stock that vested was $62 million in 2015, $50 million in 2014, and $43 million in 2013.

The weighted average award-date fair value of restricted stock awarded was $35.53 per share in 2015, $41.22 per share in 2014, and $38.07 per share in 2013.

As of December 31, 2015, $42 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 1.7 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.

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 $35 million in 2015, $26 million in 2014, and $21 million in 2013.

As a result of the termination of the pension plan (see below), employees who were hired prior to May 1, 2006 became eligible to receive profit sharing contributions effective January 1, 2014. In addition, certain of these employees are eligible to receive transition contributions related to the termination of the plan.

Deferred Compensation Plans 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)	2015	2014
Rabbi Trust Assets		
Mutual Fund Investments	$ 63	$ 83
Noble Energy Common Stock (at Fair Value)	35	51
Total Rabbi Trust Assets	$ 98	$ 134
Liability Under Related Deferred Compensation Plan	$ 98	$ 134
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	872,277	1,073,286

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 13. 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 800,000 shares, or 92%, of our common stock held in respect of one nonqualified deferred compensation plan at December 31, 2015 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next four years. Distributions of 200,000 shares were made in 2015 and 200,000 shares in 2014. In addition, plan participants sold 1,009 shares of our common stock in 2015, 19,049 shares in 2014, and 1,008 shares in 2013. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $18 million in 2015, $22 million in 2014 and $25 million in 2013.

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 (income) of $(16) million in 2015, $(25) million in 2014 and $26 million in 2013.

We also maintain other nonqualified deferred compensation plan (besides the restoration plan described below) for the benefit of certain of our employees. Deferred compensation liabilities of $119 million and $84 million were outstanding at December 31, 2015 and 2014, respectively, under those other plans.

Pension and Other Postretirement Benefit Plans We have had a noncontributory, tax-qualified defined benefit pension plan (pension plan) covering employees who were hired prior to May 1, 2006, and an unfunded, nonqualified restoration plan that provided the pension plan formula benefits that could not be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. We have also sponsored other plans, which include plans offering medical and life insurance benefits, for the benefit of our employees and retirees.

During 2015, we completed the termination of the pension plan. We liquidated the associated pension obligation through lump-sum payments to participants or the purchase of annuities on their behalf. Upon termination of the pension plan, all unamortized prior service cost and net actuarial loss remaining in AOCL was charged to expense. This amount totaled $88 million.

In coordination with the termination and liquidation of the pension plan, we also amended our restoration plan to freeze the accrual of benefits. Payments under the restoration plan will continue to be made in ordinary course without acceleration. Restoration plan participants who remain employed by us upon final liquidation and distribution of assets of the pension plan were given the option to have the lump sum present value of their restoration plan benefits converted into an account balance under our nonqualified deferred compensation plan.

During 2014, we curtailed the retiree medical program, resulting in a gain of $21 million, and, at December 31, 2014, accrued a one-time taxable cash payment of $20 million to certain employees who would have been eligible for retiree medical benefits at any point during the next 10 years.

The benefit obligations, plan assets and AOCL balances for the pension, restoration and other postretirement benefit plans are summarized below as of December 31:

	Retirement and Restoration Plans [1]		Medical and Life Plans	
(millions)	2015	2014	2015	2014
Pension or Other Benefit Obligation	$ (24)	$ (363)	$ (5)	$ (7)
Fair Value of Plan Assets	—	242	—	—
Net Amount Recognized in Consolidated Balance Sheet	(24)	(121)	(5)	(7)
Current Liabilities	(2)	(102)	(1)	(2)
Noncurrent Liabilities	(22)	(19)	(4)	(5)
Net Prior Service (Cost) Credit, Before Tax	$ (15)	$ (75)	$ 2	$ 2
Net Gains (Losses), Before Tax	(4)	(42)	—	—
Accumulated Other Comprehensive Income (Loss)	$ (19)	$ (117)	$ 2	$ 2

[1] The retirement (pension) plan was terminated during 2015. Balances at December 31, 2015 relate to the restoration plan only.

At December 31, 2014, pension plan assets were invested in cash and separately managed accounts consisting primarily of short term fixed income securities.

Net periodic benefit cost related to these plans totaled $16 million in 2015, $11 million in 2014, and $37 million in 2013.

Note 13. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheet. 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.

Inventories We carry inventory consisting 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 average cost or market.

Mutual Fund Investments Our mutual fund investments consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments Our commodity derivative instruments may include variable to fixed price commodity swaps, two-way collars, three-way collars, swaptions and extendable/enhanced swaps. We estimate the fair values of these instruments using published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold and the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 8. 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.

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) [(1)]	Significant Other Observable Inputs (Level 2) [(1)]	Significant Unobservable Inputs (Level 3) [(1)]	Adjustment [(2)]	Fair Value Measurement
December 31, 2015					
Financial Assets					
Mutual Fund Investments	$ 90	$ —	$ —	$ —	$ 90
Commodity Derivative Instruments	—	600	—	(8)	592
Financial Liabilities					
Commodity Derivative Instruments	—	(8)	—	8	—
Portion of Deferred Compensation Liability Measured at Fair Value	(98)	—	—	—	(98)
December 31, 2014					
Financial Assets					
Mutual Fund Investments	$ 111	$ —	$ —	$ —	$ 111
Commodity Derivative Instruments	—	890		—	890
Financial Liabilities					
Commodity Derivative Instruments	—	—	—	—	—
Portion of Deferred Compensation Liability Measured at Fair Value	(134)	—	—	—	(134)

(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 in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Inventory Impairment We determined that the carrying amount of certain of our materials and supplies inventory was not recoverable from future cash flows and, therefore, was impaired. Inventory was reduced to its estimated market value.

Asset Impairments We determined that the carrying amounts of certain oil and gas assets were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values.

Information about the impaired assets is as follows:

	Fair Value Measurements Using				
Description	Quoted Prices in Active Markets (Level 1) [(1)]	Significant Other Observable Inputs (Level 2) [(1)]	Significant Unobservable Inputs (Level 3) [(1)]	Net Book Value [(2)]	Total Pre-tax (Non-cash) Impairment Loss
(millions)					
Year Ended December 31, 2015					
Impaired Oil and Gas Properties	$ —	$ —	$ 752	$ 1,285	$ 533
Impaired Materials and Supplies Inventory	—	—	61	81	20
Year Ended December 31, 2014					
Impaired Oil and Gas Properties	—	—	100	600	500
Year Ended December 31, 2013					
Impaired Oil and Gas Properties	—	—	113	199	86

(1) See Note 1. Summary of Significant Accounting Policies - Fair Value Measurements for a description of the fair value hierarchy.
(2) Amount represents net book value at the date of assessment.

The fair values of the properties held and used were determined as of the date of the assessment using discounted cash flow models. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future crude oil and natural gas production, commodity prices based on sales contract terms or commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10%. The fair values of assets held for sale were based on anticipated sales proceeds less costs to sell. See Note 5. Asset Impairments.

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. See Note 10. Long-Term Debt. Fair value information regarding our debt is as follows:

	December 31, 2015		December 31, 2014	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$ 7,626	$ 7,105	$ 5,758	$ 6,179

(1) Net of unamortized discount, premium and debt issuance costs and excludes capital lease and other obligations. No floating rate debt was outstanding at December 31, 2015 or December 31, 2014.

Note 14. Earnings (Loss) Per Share

Basic earnings (loss) per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings (loss) per share of common stock include the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust (when dilutive). The following table summarizes the calculation of basic and diluted earnings (loss) per share:

	Year Ended December 31,		
(millions, except per share amounts)	2015	2014	2013
Income (Loss) from Continuing Operations	$ (2,441)	$ 1,214	$ 907
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	—	(17)	—
Income (Loss) from Continuing Operations Used for Diluted Earnings (Loss) Per Share Calculation	$ (2,441)	$ 1,197	$ 907
Weighted Average Number of Shares Outstanding, Basic[2]	402	361	359
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust[1]	—	6	4
Weighted Average Number of Shares Outstanding, Diluted	402	367	363
Earnings (Loss) from Continuing Operations Per Share, Basic	**$ (6.07)**	**$ 3.36**	**$ 2.53**
Earnings (Loss) from Continuing Operations Per Share, Diluted	**(6.07)**	**3.27**	**2.50**
Additional Information			
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	10	3	3
Weighted average option exercise price per share	$ 52.39	$ 60.30	$ 53.40

(1) For the year ended December 31, 2015, 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 from continuing operations. Therefore, inclusion of outstanding options and non-vested restricted shares in the calculation of diluted earnings (loss) per share would be anti-dilutive.

Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while our common shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings (loss) per share calculation for the year ended December 31, 2014 excludes deferred compensation gains, net of tax.

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

Note 15. Segment Information

We have operations throughout the world and manage our operations by region. The following information is grouped into four components that are all primarily in the business of crude oil, natural gas and NGL exploration, development, production and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Gabon and Sierra Leone (which we have exited)); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the Falkland Islands, Suriname, the North Sea, China (through June 2014), Nicaragua (which we have exited) and new ventures. The North Sea geographical segment is included in continuing operations in 2015 and 2014 and in discontinued operations in 2013. Income (loss) from continuing operations before income taxes for the United States and West Africa includes gains and losses on commodity derivative instruments.

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Notes to Consolidated Financial Statements

	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Year Ended December 31, 2015					
Revenues from Third Parties [1]	$ 3,043	$ 1,961	$ 580	$ 497	$ 5
Income from Equity Method Investees	90	51	39	—	—
Total Revenues	3,133	2,012	619	497	5
DD&A	2,131	1,692	326	70	43
Asset Impairments	533	158	339	36	—
Goodwill Impairment	779	779	—	—	—
Gain on Commodity Derivative Instruments	(501)	(347)	(154)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	(2,219)	(1,553)	(77)	306	(895)
Equity Method Investments	453	226	227	—	—
Additions to Long-Lived Assets	3,062	2,534	124	147	257
Goodwill at End of Year [2]	—	—	—	—	—
Total Assets at End of Year [3]	24,196	18,831	2,299	2,677	389
Year Ended December 31, 2014					
Revenues from Third Parties [1]	$ 4,931	$ 3,175	$ 1,177	$ 479	$ 100
Income from Equity Method Investees	170	9	161	—	—
Total Revenues	5,101	3,184	1,338	479	100
DD&A	1,759	1,318	299	63	79
Asset Impairments	500	392	—	14	94
Gain on Divestitures	(73)	(34)	—	—	(39)
Gain on Commodity Derivative Instruments	(976)	(604)	(372)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,710	1,150	1,222	284	(946)
Equity Method Investments	325	82	223	—	20
Additions to Long-Lived Assets	5,152	4,389	261	201	301
Goodwill at End of Year [2]	620	620	—	—	—
Total Assets at End of Year [3]	22,518	16,365	2,763	2,806	584
Year Ended December 31, 2013					
Revenues from Third Parties [1]	$ 4,809	$ 3,004	$ 1,252	$ 391	$ 162
Income from Equity Method Investees	206	—	206	—	—
Total Revenues	5,015	3,004	1,458	391	162
DD&A	1,568	1,117	261	97	93
Asset Impairments	86	39	—	47	—
Gain on Divestitures	(36)	(36)	—	—	—
Loss on Commodity Derivative Instruments	133	67	66	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,344	790	936	162	(544)
Equity Method Investments	437	184	234	—	19
Additions to Long-Lived Assets	4,534	3,475	453	420	186
Goodwill at End of Year [2]	627	627	—	—	—
Total Assets at End of Year [3]	19,598	13,094	3,199	2,753	552

(1) Revenues from third parties for all foreign countries, in total, were $1.1 billion in 2015 and $1.8 billion in both 2014 and 2013.
(2) As of December 31, 2015, our goodwill was fully impaired. See Note 4. Goodwill.
(3) Long-lived assets located in all foreign countries, in total, were $3.9 billion, $4.4 billion, and $4.5 billion at December 31, 2015, 2014, and 2013, respectively.

Note 16. Concentration of Risk

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

	Percentage of Crude Oil Sales	Percentage of Total Oil, Gas & NGL Sales
Year Ended December 31, 2015		
Glencore Energy UK Ltd	30%	18%
Shell [(1)]	18%	11%
Year Ended December 31, 2014		
Glencore Energy UK Ltd	32%	22%
Shell [(1)]	15%	10%
Year Ended December 31, 2013		
Glencore Energy UK Ltd	34%	25%
Shell [(1)]	17%	13%

(1) Includes sales to both Shell Trading (US) Company and Shell International Trading and Shipping Limited.

We believe the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Concentration of Credit Risk Certain of our financial instruments, including cash equivalents, trade and joint interest receivables and derivative instruments, may expose us to credit risk.

A significant portion of our cash is located in our 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.

Our accounts receivable result from sales of crude oil, natural gas and NGL production, and joint interest billings to our partners for their share of expenses on joint venture projects for which we are the operator. Joint venture projects, especially in deepwater, can be very capital cost intensive. Thus the receivables from our joint venture partners can become significant.

Our accounts receivable reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less. We continually monitor the creditworthiness of the counterparties, some of which are not as creditworthy as we are and may experience liquidity problems. We have obtained credit enhancements from some parties in the way of parental guarantees or letters of credit, including our largest crude oil purchaser. However, we do not have all of our trade credit or joint interest receivables protected through guarantees or credit support. Nonperformance by a trade creditor or joint venture partner could result in losses.

Our hedging activity may increase our counterparty credit risk, especially during periods of falling commodity prices. We conduct our hedging activities with a diverse group of investment grade major banks and market participants. We monitor the creditworthiness of our hedge counterparties, and our internal hedge policies provide for mark-to-market exposure limits. We use master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be “net settled” at the time of election.

Note 17. Additional Shareholders’ Equity Information

Equity Offerings On March 3, 2015, we closed an underwritten public offering of 21 million shares of common stock, par value $0.01 per share, at a price of $47.50 per share. In addition, on March 25, 2015, we completed the issuance of an additional 3.15 million shares of common stock, par value $0.01 per share, in connection with the exercise of the option of the underwriters to purchase additional shares of common stock. The aggregate net proceeds of the offerings were approximately $1.1 billion (after deducting underwriting discounts and commissions and offering expenses). We used approximately $150 million of the net proceeds to repay outstanding indebtedness under our revolving credit facility and the remainder was used for general corporate purposes, including the funding of our capital investment program.

Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31,	
	2015	2014
Common Stock Shares Issued		
Shares, Beginning of Period	402,329,325	399,841,717
Exercise of Common Stock Options	343,145	1,459,490
Restricted Stock Awards, Net of Forfeitures	1,847,802	1,028,118
Public Equity Offering	24,150,000	—
Shares Exchanged in Rosetta Merger	41,048,240	—
Shares, End of Period	469,718,512	402,329,325
Treasury Stock		
Shares, Beginning of Period	37,635,890	37,600,051
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	490,744	254,888
Rabbi Trust Shares Distributed and/or Sold	(201,009)	(219,049)
Shares, End of Period	37,925,625	37,635,890

Accumulated other comprehensive loss in the shareholders' equity section of the balance sheet included:

	Accumulated Other Comprehensive Loss		
(millions)	Interest Rate Cash Flow Hedges	Pension-Related and Other	Total
December 31, 2012	$ (25)	$ (88)	$ (113)
Realized Amounts Reclassified Into Earnings	1	12	13
Unrealized Change in Fair Value	—	(17)	(17)
December 31, 2013	(24)	(93)	(117)
Realized Amounts Reclassified Into Earnings	1	11	12
Unrealized Change in Fair Value	—	15	15
December 31, 2014	(23)	(67)	(90)
Realized Amounts Reclassified Into Earnings	1	62	63
Unrealized Change in Fair Value	—	(6)	(6)
December 31, 2015	$ (22)	$ (11)	$ (33)

All amounts in the table above are reported net of tax, using an effective income tax rate of 35%.

AOCL at December 31, 2015 included deferred losses of $22 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due March 2041.

Note 18. 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, 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 oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the Court on June 2, 2015.

The Consent Decree, which alleges violations of the Colorado Air Pollution Prevention and Control Act and Colorado's federal approved State Implementation Plan, specifically Colorado Air Quality Control Commission Regulation Number 7, requires us to perform certain injunctive relief activities to complete mitigation projects and supplemental environmental projects (SEP), and pay a civil penalty. Costs associated with the settlement consist of $4.95 million in civil penalties, $4.5 million in mitigation projects, and $4 million in SEPs. Costs associated with the injunctive relief are not yet precisely quantifiable as they will be determined in accordance with the outcome of evaluations on the adequate design, operation, and maintenance of certain aspects of tank systems to handle potential peak instantaneous vapor flow rates between now and mid-2017.

Compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries. The Consent Decree sets forth a detailed compliance schedule with deadlines for achievement of milestones through early 2019. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that which is required under existing Colorado regulations. Inspection and monitoring findings may influence decisions to temporarily shut in or permanently plug and abandon wells and associated tank batteries.

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

Colorado Air Compliance Order on Consent In December 2015, we received a proposed Compliance Order on Consent (COC) from the Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance associated with certain engines subject to various General Permit 02 conditions and/or individual permit conditions as well as certain emission control devices subject to various individual permit conditions. The COC, which provides for an opportunity to further discuss the offer of settlement, has not yet been executed. At present, the COC seeks payment of a reduced penalty of $247,625 and provides the opportunity to mitigate up to 80% of the reduced penalty by pursuing a SEP or SEPs. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

CONSOL Carried Cost Obligation In accordance with our Marcellus Shale joint venture arrangement with a subsidiary of CONSOL Energy Inc. (CONSOL), we agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs, capped at $400 million each year (CONSOL Carried Cost Obligation). The remaining obligation totaled approximately $1.6 billion at December 31, 2015.

The CONSOL Carried Cost Obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and remain suspended until average Henry Hub natural gas prices equal or exceed $4.00 per MMBtu for three consecutive months. Due to low natural gas prices, the CONSOL Carried Cost Obligation was suspended from the end of 2011 until February 28, 2014. We began funding a portion of CONSOL's working interest share of certain drilling and completion costs as of March 1, 2014; however, the funding was suspended again in November 2014 due to lower natural gas prices. Based on the December 31, 2015 NYMEX Henry Hub natural gas price curve, we forecast the CONSOL Carried Cost Obligation will be suspended in 2016.

Marcellus Shale Firm Transportation Agreements During 2014, we signed precedent agreements for firm transportation (the Agreements) to flow approximately 320 MMBtu per day of our Marcellus Shale natural gas production to various markets outside of the Marcellus Basin. The Agreements are for firm transportation services on new pipeline projects to be constructed by, and connecting to, existing and new interstate pipeline systems. The pipeline projects are expected to be complete and operational in 2017 and 2018. Our financial commitment for these Agreements is approximately $1.5 billion, undiscounted, over a 15-year period. Final agreements are subject to various conditions, including regulatory approval of the pipeline projects. 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 $84 million in 2015, $69 million in 2014, and $50 million in 2013.

Minimum commitments as of December 31, 2015 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations	Operating Lease Obligations	Capital Lease and Other Obligations[1]	Total
2016	$ 291	$ 217	$ 42	$ 76	$ 626
2017	167	248	44	81	540
2018	22	314	39	79	454
2019	16	305	26	50	397
2020	10	270	26	47	353
2021 and Thereafter	9	1,816	168	179	2,172
Total	$ 515	$ 3,170	$ 345	$ 512	$ 4,542

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 10. Long-Term Debt.

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, natural gas and NGL reserves and exploration and production activities.

Reserves

There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. Crude oil, natural gas and NGL 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, natural gas and NGLs that are ultimately recovered.

Economic producibility of reserves is dependent on the crude oil, natural gas and NGL prices used in the reserves estimate. We based our December 31, 2015, 2014, and 2013 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, natural gas or NGL prices could result in negative reserves revisions.

Reserves Estimates 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 regional management and senior engineering staff with final approval by the Senior Vice President - Corporate Development and certain members of senior management. For additional information regarding our reserves estimation process and internal controls see Items 1. and 2. Business and Properties – Proved Reserves Disclosures – 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, 2015. See Items 1. and 2. Business and Properties – Proved Reserves Disclosures.

Geographic Areas Our supplemental disclosures are grouped by geographic area, which include the United States; West Africa (Equatorial Guinea, Cameroon, Gabon, and Sierra Leone (which we exited in 2015)); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, China (through June 2014), Falkland Islands, Nicaragua, Suriname and new ventures. The North Sea geographical segment is included in continuing operations in 2015 and 2014 and discontinued operations in 2013.

Operations in Cyprus, Equatorial Guinea, Gabon and Suriname are conducted in accordance with the terms of PSCs. In Cameroon, we operate in accordance with the terms of a PSC and a mining concession. Operations in the Falkland Islands, the North Sea, Israel, and other foreign locations are conducted in accordance with concession agreements, permits or licenses.

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 with the cost of a new well.

Undeveloped Oil and Gas Reserves Proved 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 natural gas, natural gas liquids and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

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	Other Int'l [1]	Total
Proved Reserves as of:				
December 31, 2012	171	84	13	268
Revisions of Previous Estimates [2]	14	5	—	19
Extensions, Discoveries and Other Additions [3]	85	—	1	86
Purchase of Minerals in Place [4]	3	—	—	3
Sale of Minerals in Place [5]	(14)	—	(3)	(17)
Production [6]	(23)	(12)	(2)	(37)
December 31, 2013	236	77	9	322
Revisions of Previous Estimates [2]	(5)	1	—	(4)
Extensions, Discoveries and Other Additions [3]	30	—	—	30
Purchase of Minerals in Place [4]	—	—	—	—
Sale of Minerals in Place [5]	—	—	(5)	(5)
Production [6]	(25)	(13)	(1)	(39)
December 31, 2014	236	65	3	304
Revisions of Previous Estimates [2]	(56)	(5)	—	(61)
Extensions, Discoveries and Other Additions [3]	42	—	—	42
Purchase of Minerals in Place [4]	65	—	—	65
Sale of Minerals in Place [5]	(2)	—	—	(2)
Production [6]	(29)	(12)	—	(41)
December 31, 2015	256	48	3	307
Proved Developed Reserves as of				
December 31, 2012	87	48	8	143
December 31, 2013	102	64	8	174
December 31, 2014	119	52	3	174
December 31, 2015	137	34	3	174
Proved Undeveloped Reserves as of				
December 31, 2012	83	35	5	123
December 31, 2013	134	12	2	148
December 31, 2014	117	13	—	130
December 31, 2015	119	14	—	133

(1) Other International includes China (through June 2014), the North Sea and Israel.

(2) The 2013 US revisions were primarily associated with positive performance revisions to our DJ Basin and Marcellus Shale programs as well as 2 MMBbls of positive price revisions. Equatorial Guinea revisions are associated with positive performance revisions to the Alba field.

The 2014 US revisions are primarily associated with positive performance revisions to our Marcellus Shale program and our deepwater Gulf of Mexico Swordfish field, offset by DJ Basin negative revisions due to a revised drilling plan in response to the current commodity price environment.

The 2015 US revisions were primarily associated with negative price revisions of 70 MMBbls to our onshore programs due to a decline in the 12-month average price of crude oil, offset by positive revisions of 14 MMBbls due to producing well performance and optimized lateral lengths in the Permian Basin and Eagle Ford Shale. Equatorial Guinea revisions are associated with negative price revisions of 5 MMBbls.

(3) The 2013 increase in US reserves included an increase of 89 MMBbls in the DJ Basin and 9 MMBbls from Marcellus Shale development as well as 15 MMBbls in the deepwater Gulf of Mexico from sanctioned development projects. The increase in Equatorial Guinea was attributable to future infill development at the Alba field. The increase to Other International included 1 MMBbls in China.

The 2014 increase in US reserves included an increase of 21 MMBbls in the DJ Basin and 2 MMBbls from Marcellus Shale development as well as 7 MMBbls in the deepwater Gulf of Mexico due to sanction of the Dantzler development project.

The 2015 increase in US reserves is attributable to 42 MMBbls from DJ Basin development.

(4) The 2015 increase is attributable to reserves acquired in the Rosetta Merger.

(5) In 2013, sales include divestitures of non-core, onshore US and North Sea assets as well as the net impact of the DJ Basin acreage exchange.

In 2014, we sold non-core onshore US and China assets.

In 2015, we sold non-core onshore US assets.

(6) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2015, 2014, 2013.

See Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. Merger, Acquisitions and Divestitures.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

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	Equatorial Guinea	Israel (1)	Other Int'l (2)	Total
Proved Reserves as of:					
December 31, 2012	1,987	718	2,250	9	4,964
Revisions of Previous Estimates (3)	262	24	124	—	410
Extensions, Discoveries and Other Additions (4)	587	41	181	—	809
Purchase of Minerals in Place (5)	126	—	—	—	126
Sale of Minerals in Place (6)	(145)	—	—	(6)	(151)
Production	(161)	(92)	(76)	(1)	(330)
December 31, 2013	2,656	691	2,479	2	5,828
Revisions of Previous Estimates (3)	58	11	21	—	90
Extensions, Discoveries and Other Additions (4)	433	—	—	—	433
Purchase of Minerals in Place (5)	—	—	—	—	—
Sale of Minerals in Place (6)	(154)	—	—	(2)	(156)
Production	(189)	(89)	(84)	—	(362)
December 31, 2014	2,804	613	2,416	—	5,833
Revisions of Previous Estimates (3)	(705)	4	(20)	—	(721)
Extensions, Discoveries and Other Additions (4)	257	—	—	—	257
Purchase of Minerals in Place (5)	629	—	—	—	629
Sale of Minerals in Place (6)	(16)	—	—	—	(16)
Production	(258)	(83)	(92)	—	(433)
December 31, 2015	2,711	534	2,304	—	5,549
Proved Developed Reserves as of					
December 31, 2012	1,042	514	18	8	1,582
December 31, 2013	1,212	457	2,046	2	3,717
December 31, 2014	1,459	377	1,973	—	3,809
December 31, 2015	1,813	247	1,879	—	3,939
Proved Undeveloped Reserves as of					
December 31, 2012	945	204	2,232	1	3,382
December 31, 2013	1,444	234	433	—	2,111
December 31, 2014	1,345	236	443	—	2,024
December 31, 2015	898	287	425	—	1,610

(1) In accordance with the terms of the Israel Natural Gas Framework, we will be required to reduce our ownership in the Tamar field to 25% within six years. See Items 1. and 2. Business and Properties – Update on Israel – Israel Natural Gas Framework.

(2) Other International includes China (through June 2014) and the North Sea. See Note 3. Merger, Acquisitions and Divestitures.

(3) The 2013 US revisions were primarily associated with positive performance revisions to our DJ Basin and Marcellus Shale programs as well as 68 Bcf of positive price revisions. Equatorial Guinea revisions are associated with positive performance revisions to the Alba field. Israel revisions are primarily associated with positive performance revisions to the Tamar field.

The 2014 US revisions were primarily associated with a positive performance revision to our Marcellus Shale program offset by a negative revision to our DJ Basin program due to a revised drilling program in response to the current commodity price environment. Equatorial Guinea revisions are associated with positive performance revisions to the Alba field. Israel revisions are primarily associated with positive performance revisions to the Tamar field.

The 2015 US revisions are primarily associated with negative price revisions of 1.1 Tcf to our onshore programs due to a decline in the 12-month average price, offset by a positive revision primarily to our Marcellus Shale program due to positive well performance. Equatorial Guinea revisions are associated with positive performance revisions to the Alba field. Israel revisions are primarily associated with negative performance revisions in the Mari-B field.

(4) The 2013 increase in US reserves included an increase of 250 Bcf in the DJ Basin and 317 Bcf from Marcellus Shale development as well as 18 Bcf in the deepwater Gulf of Mexico primarily from sanctioned development projects. Increases in Equatorial Guinea are attributable to future infill development at the Alba and Alen fields. Increases to Israel are due to discovery and sanction of the Tamar Southwest field.

The 2014 increase in US reserves included an increase of 110 Bcf in the DJ Basin and 309 Bcf from Marcellus Shale development as well as 14 Bcf in the deepwater Gulf of Mexico.

The 2015 increase in US reserves included an increase of 176 Bcf in the DJ Basin and 81 Bcf from Marcellus Shale development due to positive producing well performance and optimized lateral lengths.

(5) The 2013 increase is attributable to the acquisition of additional acreage in the Marcellus Shale and other onshore US locations.

The 2015 increase is attributable to reserves acquired in the Rosetta Merger.

(6) In 2013, sales include divestitures of non-core, onshore US and North Sea assets as well as the net impact of the DJ Basin acreage exchange.

In 2014, we sold non-core onshore US and China assets.

In 2015, we sold non-core onshore US in the DJ Basin.

See Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. Merger, Acquisitions and Divestitures.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

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	Other Int'l	Total
Proved Reserves as of:				
December 31, 2012	72	17	—	89
Revisions of Previous Estimates	6	2	—	8
Extensions, Discoveries and Other Additions (2)	28	1	—	29
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place	(5)	—	—	(5)
Production	(6)	(2)	—	(8)
December 31, 2013	95	18	—	113
Revisions of Previous Estimates	7	—	—	7
Extensions, Discoveries and Other Additions (2)	18	—	—	18
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place	—	—	—	—
Production	(7)	(3)	—	(10)
December 31, 2014	113	15	—	128
Revisions of Previous Estimates (1)	(37)	—	—	(37)
Extensions, Discoveries and Other Additions (2)	15	—	—	15
Purchase of Minerals in Place (3)	100	—	—	100
Sale of Minerals in Place	(1)	—	—	(1)
Production	(14)	(2)	—	(16)
December 31, 2015	176	13	—	189
Proved Developed Reserves as of				
December 31, 2012	42	12	—	54
December 31, 2013	44	11	—	55
December 31, 2014	64	8	—	72
December 31, 2015	101	5	—	106
Proved Undeveloped Reserves as of				
December 31, 2012	30	5	—	35
December 31, 2013	51	7	—	58
December 31, 2014	49	7	—	56
December 31, 2015	75	8	—	83

(1) The 2015 US revisions are primarily associated with negative price revisions of 44 MMBbls to our onshore programs due to a decline in the 12-month average price, offset by a positive revision from our Marcellus Shale program due to positive well performance.

(2) The 2013 additions in US reserves included an increase of 19 MMBbls in the DJ Basin and 8 MMBbls from Marcellus Shale development.

The 2014 additions in US reserves included an increase of 8 MMBbls in the DJ Basin and 8 MMBbls from Marcellus Shale development.

The 2015 additions include 14 MMBbls due to positive producing well performance and optimized lateral lengths in the DJ Basin .

(3) The 2015 increase is attributable to reserves acquired in the Rosetta Merger.

See also Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs).

Results of Operations for Oil and Gas Producing Activities (Unaudited) Aggregate results of operations for crude oil and natural gas producing activities are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [(1)]	Total
(millions)					
Year Ended December 31, 2015					
Revenues	$ 1,961	$ 580	$ 497	$ 5	$ 3,043
Production Costs [(2)]	800	145	67	15	1,027
Exploration Expense	202	1	6	279	488
DD&A	1,692	326	70	43	2,131
Asset Impairments	158	339	36	—	533
Income (Loss) before Income Taxes	(891)	(231)	318	(332)	(1,136)
Income Tax Expense (Benefit) [(3)]	(312)	(58)	84	(5)	(291)
Results of Operations [(4)]	$ (579)	$ (173)	$ 234	$ (327)	$ (845)
Year Ended December 31, 2014					
Revenues	$ 3,175	$ 1,177	$ 479	$ 100	$ 4,931
Production Costs [(2)]	688	147	54	69	958
Exploration Expense	268	18	4	208	498
DD&A	1,318	299	63	79	1,759
Asset Impairments	392	—	14	94	500
Income before Income Taxes	509	713	344	(350)	1,216
Income Tax Expense [(3)]	178	178	94	18	468
Results of Operations [(4)]	$ 331	$ 535	$ 250	$ (368)	$ 748
Year Ended December 31, 2013					
Revenues	$ 3,004	$ 1,252	$ 391	$ 199	$ 4,846
Production Costs [(2)]	653	120	60	68	901
Exploration Expense	124	12	3	276	415
DD&A	1,117	261	97	95	1,570
Asset Impairments	39	—	47	—	86
Income before Income Taxes	1,071	859	184	(240)	1,874
Income Tax Expense [(3)]	375	215	69	26	685
Results of Operations [(4)]	$ 696	$ 644	$ 115	$ (266)	$ 1,189

(1) Other International includes the North Sea, China (through June 30, 2014), Cameroon, Gabon, Sierra Leone (which we exited in 2015), Cyprus, Nicaragua (which we exited in 2015), Falkland Islands, Suriname, Corporate and other new ventures. See Note 3. Merger, Acquisitions and Divestitures.

(2) Production costs consist of lease operating expense, production and ad valorem taxes, transportation expense, and general and administrative expense supporting oil and gas operations.

(3) Income tax expense is based upon respective corporate statutory tax rates. During 2015, 2014 and 2013, 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.

(4) Results of operations exclude the mark-to-market gain or loss on commodity derivative instruments, corporate overhead and interest costs. See Note 8. Derivative Instruments and Hedging Activities.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) [1]

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [2]	Total
(millions)					
Year Ended December 31, 2015					
Property Acquisition Costs					
Proved [3]	$ 1,613	$ —	$ —	$ —	$ 1,613
Unproved [3]	1,478	—	—	2	1,480
Exploration Costs [4]	206	22	22	234	484
Development Costs [5]	2,455	75	104	10	2,644
Total Consolidated Operations	$ 5,752	$ 97	$ 126	$ 246	$ 6,221
Company's Share of CONE Gathering Development Costs	$ 104	$ —	$ —	$ —	$ 104
Year Ended December 31, 2014					
Property Acquisition Costs					
Unproved [3]	$ 246	$ —	$ —	$ 3	$ 249
Exploration Costs [4]	485	61	60	64	670
Development Costs [5]	3,685	211	144	78	4,118
Total Consolidated Operations	$ 4,416	$ 272	$ 204	$ 145	$ 5,037
Company's Share of CONE Gathering Development Costs	$ 71	$ —	$ —	$ —	$ 71
Year Ended December 31, 2013					
Property Acquisition Costs					
Unproved [3]	209	—	—	—	209
Exploration Costs [4]	340	213	119	338	1,010
Development Costs [5]	2,847	223	163	62	3,295
Total Consolidated Operations	$ 3,396	$ 436	$ 282	$ 400	$ 4,514
Company's Share of CONE Gathering Development Costs	$ 57	$ —	$ —	$ —	$ 57

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes the North Sea, China (through June 30, 2014), Cameroon, Gabon, Sierra Leone, Cyprus, Nicaragua, Falkland Islands and Suriname. See Note 3. Merger, Acquisitions and Divestitures.

(3) 2015 proved and unproved property acquisitions include amounts allocated from the Rosetta Merger. See Note 3. Merger, Acquisitions and Divestitures.

2014 unproved property acquisition costs include $68 million and $160 million related to expanding our positions in the DJ Basin and Marcellus Shale, respectively, and $16 million for deepwater Gulf of Mexico lease blocks.

2013 unproved property acquisition costs include $166 million and $27 million related to expanding our positions in the Marcellus Shale and DJ Basin, respectively, and $12 million for deepwater Gulf of Mexico lease blocks.

(4) 2015 exploration costs include drilling and completion of $4 million in the DJ Basin, $22 million in the deepwater Gulf of Mexico, $1 million in Equatorial Guinea and $4 million in Cyprus.

2014 exploration costs include drilling and completion of $14 million in the DJ Basin, $2 million in the Marcellus Shale, $117 million in the deepwater Gulf of Mexico, $16 million in Equatorial Guinea, $13 million in Israel and $4 million in Cyprus.

2013 exploration costs include drilling and completion of $11 million in the DJ Basin, $19 million in the Marcellus Shale, $106 million in the deepwater Gulf of Mexico, $23 million in northeast Nevada, $187 million in Equatorial Guinea, $93 million in Israel and $115 million in Cyprus.

(5) Worldwide development costs include amounts spent to develop PUDs of approximately $1.5 billion in 2015, $2.0 billion in 2014, and $1.0 billion in 2013.

US development costs include gathering and processing assets acquired in the Rosetta Merger in 2015 and increases in asset retirement obligations of $194 million in 2015, $106 million in 2014, and $214 million in 2013.

EG development costs include increases (decreases) in asset retirement obligations of $(10) million in 2015, $34 million in 2014, and $9 million in 2013.

Israel development costs include increases in asset retirement obligations of $46 million in 2015, $19 million in 2014, and $14 million in 2013.

Other International development costs include increases in asset retirement obligations of $2 million in 2015, $71 million in 2014, and $9 million in 2013.

Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited) Aggregate capitalized costs relating to crude oil and natural gas producing activities are as follows:

	December 31,	
	2015	2014
(millions)		
Unproved Oil and Gas Properties [1]	$ 2,151	$ 1,487
Proved Oil and Gas Properties [2]	29,069	24,112
Total Oil and Gas Properties	31,220	25,599
Accumulated DD&A	(10,439)	(7,820)
Net Capitalized Costs	$ 20,781	$ 17,779
Company's Share of CONE Gathering Net Capitalized Costs	$ 433	$ 290

(1) Unproved oil and gas property cost at December 31, 2015 include previous acquisition costs of $1.2 billion related to the Eagle Ford Shale and Permian Basin properties and $566 million related to the Marcellus Shale.

Unproved oil and gas property cost at December 31, 2014 include previous acquisition costs of $655 million related to the Marcellus Shale.

See Note 3. Merger, Acquisitions and Divestitures.

(2) Proved oil and gas properties at December 31, 2015 include asset retirement costs of $864 million and exclude assets held for sale of $67 million related to the Karish and Tanin natural gas discoveries offshore Israel.

Proved oil and gas properties at December 31, 2014 include asset retirement costs of $639 million and exclude assets held for sale of $180 million.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(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.

	United States	Equatorial Guinea	Israel (1)	Other Int'l (2)	Total
(millions)					
December 31, 2015					
Future Cash Inflows (3)	$ 19,099	$ 2,965	$ 11,835	$ —	$ 33,899
Future Production Costs (4)	8,728	1,351	1,128	—	11,207
Future Development Costs (5)	4,092	101	682	—	4,875
Future Income Tax Expense (6)	837	189	5,281	—	6,307
Future Net Cash Flows	5,442	1,324	4,744	—	11,510
10% Annual Discount for Estimated Timing of Cash Flows	2,100	262	2,452	—	4,814
Standardized Measure of Discounted Future Net Cash Flows	$ 3,342	$ 1,062	$ 2,292	$ —	$ 6,696
December 31, 2014					
Future Cash Inflows (3)	$ 36,352	$ 7,402	$ 15,110	$ 11	$ 58,875
Future Production Costs (4)	10,337	2,294	1,829	8	14,468
Future Development Costs (5)	7,272	186	724	100	8,282
Future Income Tax Expense	5,448	1,075	2,365	—	8,888
Future Net Cash Flows	13,295	3,847	10,192	(97)	27,237
10% Annual Discount for Estimated Timing of Cash Flows	6,040	995	6,240	(17)	13,258
Standardized Measure of Discounted Future Net Cash Flows	$ 7,255	$ 2,852	$ 3,952	$ (80)	$ 13,979
December 31, 2013					
Future Cash Inflows (3)	$ 34,611	$ 9,393	$ 15,046	$ 726	$ 59,776
Future Production Costs (4)	8,901	2,364	1,742	293	13,300
Future Development Costs (5)	7,613	212	848	133	8,806
Future Income Tax Expense	5,889	1,578	2,408	88	9,963
Future Net Cash Flows	12,208	5,239	10,048	212	27,707
10% Annual Discount for Estimated Timing of Cash Flows	5,867	1,515	6,213	22	13,617
Standardized Measure of Discounted Future Net Cash Flows	$ 6,341	$ 3,724	$ 3,835	$ 190	$ 14,090

(1) In accordance with the Israel Natural Gas Framework, we will be required to reduce our ownership in the Tamar field to 25% within six years. See Items 1. and 2. Business and Properties – Update on Israel – Israel Natural Gas Framework.

(2) Other International includes China (through June 30, 2014) and the North Sea. See Note 3. Merger, Acquisitions and Divestitures.

(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. Specifically, Other International future development costs as of December 31, 2014 primarily includes the MacCulloch field (North Sea) abandonment costs. See Note 9. 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. For 2015, future income tax expense for Israel also includes the effect of estimated future profit levy taxes.

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	Equatorial Guinea	Israel	Other Int'l [1]	Total
December 31, 2015					
Average Crude Oil and Condensate Price per Bbl	$ 42.03	$ 51.03	$ 48.23	$ —	$ 43.50
Average Natural Gas Price per Mcf	2.16	0.25	5.08	—	3.18
Average NGL Price per Bbl	14.15	29.92	—	—	15.23
December 31, 2014					
Average Crude Oil and Condensate Price per Bbl	$ 86.88	$ 97.88	$ 90.88	$ 102.28	$ 89.27
Average Natural Gas Price per Mcf	3.99	0.25	6.14	—	4.49
Average NGL Price per Bbl	41.58	59.96	—	—	43.85
December 31, 2013					
Average Crude Oil and Condensate Price per Bbl	$ 89.76	$ 98.08	$ 97.30	$ 104.94	$ 92.44
Average Natural Gas Price per Mcf	3.59	0.25	5.94	—	4.19
Average NGL Price per Bbl	40.98	66.6	—	—	40.98

[1] Other International includes China (through June 2014) and the North Sea. See Note 3. Merger, Acquisitions and Divestitures.

The discounted future net cash flows are computed using a 12-month average commodity price applied to our year-end quantities of proved reserves. 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 $10.00 per Bbl reduction in the average price of crude oil from the 12-month average price for 2015 would reduce the discounted future net cash flows before income taxes by approximately $2.9 billion. We estimate that a $0.50 per Mcf reduction in the average price of natural gas from the 12-month average price for 2015 would reduce the discounted future net cash flows before income taxes by approximately $1.3 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, natural gas and NGL 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 $0.7 billion in 2016, $0.7 billion in 2017 and $0.8 billion in 2018.

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, natural gas and NGL 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.

Imbalance receivables and liabilities are as follows:

	Year Ended December 31,		
	2015	2014	2013
(millions)			
Imbalance Receivables	$ 34	$ 34	$ 31
Imbalance Liabilities	34	33	29

Imbalance receivables and imbalance liabilities have been excluded from the standardized measure of discounted future net cash flows.

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, natural gas and NGL reserves are as follows:

	Year Ended December 31,		
	2015	2014	2013
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$ 13,979	$ 14,090	$ 13,081
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(2,026)	(4,027)	(3,937)
Net Changes in Prices and Production Costs [1]	(12,603)	(1,090)	(237)
Extensions, Discoveries and Improved Recovery, Less Related Costs	442	1,457	3,386
Changes in Estimated Future Development Costs	1,203	(2,179)	(1,825)
Development Costs Incurred During the Period	2,639	4,042	3,195
Revisions of Previous Quantity Estimates	(1,051)	162	1,541
Purchases of Minerals in Place [2]	2,747	—	78
Sales of Minerals in Place	(46)	(268)	(768)
Accretion of Discount	1,789	1,919	1,765
Net Change in Income Taxes [3]	2,075	671	(780)
Change in Timing of Estimated Future Production and Other [4]	(2,452)	(798)	(1,409)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	(7,283)	(111)	1,009
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$ 6,696	$ 13,979	$ 14,090

(1) Decrease in 2015 is driven primarily by lower 12-month average commodity prices.
(2) Purchase of minerals in 2015 is driven by reserves acquired in the Rosetta Merger.
(3) Increase in 2015 is reflective of lower estimated future income tax expense primarily driven by lower 12-month average commodity prices. For 2015, future income tax expense for Israel includes the effect of estimated future profit levy taxes which partially offset the increase in future net cash flows.
(4) Decrease in 2015 reflects revisions in our estimated timing of production and development activity.

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)					
2015 [1] [3]					
Revenues	$ 758	$ 728	$ 801	$ 846	$ 3,133
Income (Loss) from Continuing Operations Before Income Taxes	(42)	(293)	(259)	(1,627)	(2,219)
Income (Loss) from Continuing Operations	(22)	(109)	(283)	(2,028)	(2,441)
Net Income (Loss)	(22)	(109)	(283)	(2,028)	(2,441)
Basic Earnings (Loss) Per Share [4]					
Net Income (Loss)	(0.06)	(0.28)	(0.67)	(4.73)	(6.07)
Diluted Earnings (Loss) Per Share [4] [5]					
Net Income (Loss)	(0.06)	(0.28)	(0.67)	(4.73)	(6.07)
2014 [2] [3]					
Revenues	$ 1,379	$ 1,383	$ 1,269	$ 1,070	$ 5,101
Income from Continuing Operations Before Income Taxes	277	233	576	624	1,710
Income from Continuing Operations	200	192	419	402	1,214
Net Income	200	192	419	402	1,214
Basic Earnings Per Share [4]					
Net Income	0.56	0.53	1.16	1.11	3.36
Diluted Earnings Per Share [4] [5]					
Net Income	0.55	0.52	1.12	1.05	3.27

[1] First quarter 2015 included the following:

- $150 million gain on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $60 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $27 million property impairment charges (See Note 5. Asset Impairments).

Second quarter 2015 included the following:

- $87 million loss on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $274 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $15 million property impairment charges (See Note 5. Asset Impairments).

Third quarter 2015 included the following:

- $267 million gain on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $17 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $71 million of other operating expenses associated with the Rosetta Merger.

Fourth quarter 2015 included the following:

- $171 million gain on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $157 million (See Note 8. Derivative Instruments and Hedging Activities);
- $779 million goodwill impairment charge (See Note 4. Goodwill); and
- $490 million property impairment charges (See Note 5. Asset Impairments).

[2] First quarter 2014 included the following:

- $75 million loss on commodity derivative instruments, including non-cash portion of the loss on commodity derivative instruments of $42 million (See Note 8. Derivative Instruments and Hedging Activities);
- $97 million property impairment charges (See Note 5. Asset Impairments); and
- $1 million pre-tax loss on sale of non-core assets (See Note 3. Merger, Acquisitions and Divestitures).

Second quarter 2014 included the following:

- $236 million loss on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $187 million (See Note 8. Derivative Instruments and Hedging Activities);
- $34 million property impairment charges (See Note 5. Asset Impairments); and
- $42 million pre-tax gain on sale of non-core assets (See Note 3. Merger, Acquisitions and Divestitures).

Third quarter 2014 included the following:

- $385 million gain on commodity derivative instruments, including the non-cash portion of the gain on commodity derivative instruments of $397 million (See Note 8. Derivative Instruments and Hedging Activities);
- $33 million property impairment charges (See Note 5. Asset Impairments); and
- $30 million pre-tax gain on sale of non-core assets (See Note 3. Merger, Acquisitions and Divestitures).

Fourth quarter 2014 included the following:

- $903 million gain on commodity derivative instruments, including the non-cash portion of gain on commodity derivative instruments of $779 million (See Note 8. Derivative Instruments and Hedging Activities);
- $2 million pre-tax gain on sale of non-core assets (See Note 3. Merger, Acquisitions and Divestitures); and
- $336 million property impairment charges (See Note 5. Asset Impairments).

(3) The sum of the individual quarterly earnings (loss) may not agree with year-to-date earnings as each quarterly computation is based on the earnings for the individual quarter as reported with rounding applied.

(4) The sum of the individual quarterly earnings (loss) per share amounts may not agree with year-to-date earnings per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of shares outstanding during that quarter.

(5) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while the Noble Energy shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculation for both the three month period ended December 31, 2014 and the year ended December 31, 2014 excludes deferred compensation gains of $17 million, net of tax.

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 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 such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, 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 are designed and effective to ensure that information required to be disclosed in the reports that we file or furnish 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.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

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

Our management is also responsible for establishing and maintaining adequate internal controls 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 controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with US GAAP.

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 procedures may deteriorate.

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2015. As noted in the management report called for by Item 308(a) of Regulation S-K and incorporated by reference above, our assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Rosetta Merger on July 20, 2015. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. We are in the process of integrating Rosetta's and our internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient internal control over financial reporting throughout this integration process. Except as noted above, there were no changes in our internal control over financial reporting during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on our assessment, our internal controls over financial reporting were effective.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2015.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2015.

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 2016 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2015.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2015.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2016 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2015.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

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 17, 2016	By: /s/ David L. Stover David L. Stover, Chairman of the Board, President and Chief Executive Officer
Date: February 17, 2016	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date: February 17, 2016	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, President and Chief Executive Officer (Principal Executive Officer)	February 17, 2016
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 17, 2016
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 17, 2016
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 17, 2016
/s/ Michael A. Cawley Michael A. Cawley	Director	February 17, 2016
/s/ Edward F. Cox Edward F. Cox	Director	February 17, 2016
/s/ James E. Craddock James E. Craddock	Director	February 17, 2016
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 17, 2016
/s/ Eric P. Grubman Eric P. Grubman	Director	February 17, 2016
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 17, 2016
/s/ Scott D. Urban Scott D. Urban	Director	February 17, 2016
/s/ William T. Van Kleef William T. Van Kleef	Director	February 17, 2016
/s/ Molly K. Williamson Molly K. Williamson	Director	February 17, 2016

INDEX TO EXHIBITS

Exhibit **

Exhibit Number		
2.1	—	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc. including Appendix I (Definitions) thereto (filed as Exhibit 2.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference).
2.2	—	Agreement and Plan of Merger, dated as of May 10, 2015, by and among Noble Energy, Inc., Bluebonnet Merger Sub Inc. and Rosetta Resources Inc. (filed as Exhibit 2.1 of the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed on May 11, 2015 and incorporated herein by reference).
3.1	—	Certificate of Incorporation, as amended through April 29, 2015, of the Registrant (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 and incorporated herein by reference).
3.2	—	By-Laws of Noble Energy, Inc. as amended through October 20, 2015 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 20, 2015) filed on October 22, 2015 and incorporated herein by reference).
4.1	—	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed as Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.2	—	Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.3	—	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 and incorporated herein by reference).
4.4	—	First Supplemental Indenture dated as of February 27, 2009, 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 8.25% Notes due 2019. (including the form of 2019 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: February 24, 2009) filed February 27, 2009 and incorporated herein by reference).
4.5	—	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 and incorporated herein by reference).
4.6	—	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 and incorporated herein by reference).
4.7	—	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 and incorporated herein by reference).
4.8	—	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 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 and incorporated herein by reference).
4.9	—	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 and incorporated herein by reference).

4.10	—	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7¼% Notes Due 2023 (including the form of 2023 Notes) (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.11	—	Indenture dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.12	—	First Indenture Supplement dated as of April 2, 1997, to Indenture dated as of April 1, 1997, between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 8% Senior Notes Due 2027 (including the form of 2027 Notes) (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.13	—	Second Indenture Supplement, dated as of August 1, 1997, to Indenture dated as of April 1, 1997, between the Registrant and U.S. Trust Company of Texas, N.A. as trustee, relating to the Registrant's 7¼% Senior Debentures Due 2097 (including the form of 2097 Notes) (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
10.1*	—	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 and incorporated herein by reference).
10.2*	—	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 and incorporated herein by reference).
10.3*	—	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 and incorporated herein by reference).
10.4*	—	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 Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.5*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.6	—	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 and incorporated herein by reference).
10.7	—	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: August 27, 2015) filed August 31, 2015 and incorporated herein by reference).
10.8	—	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: October 3, 2013) filed October 9, 2013 and incorporated herein by reference).
10.9*	—	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 and incorporated herein by reference).
10.10*	—	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 and incorporated herein by reference).
10.11*	—	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 and incorporated herein by reference).
10.12*	—	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 and incorporated herein by reference).

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10.13*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (as amended and restated effective October 20, 2015) (filed as Exhibit 10.1 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 and incorporated herein by reference).
10.14*	—	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 and incorporated herein by reference).
10.15*	—	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 on February 2, 2009 and incorporated herein by reference).
10.16*	—	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 and incorporated herein by reference).
10.17*	—	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 and incorporated herein by reference).
10.18*	—	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 and incorporated herein by reference).
10.19*	—	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 and incorporated herein by reference).
10.20*	—	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 and incorporated herein by reference).
10.21*	—	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 and incorporated herein by reference).
10.22*	—	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 and incorporated herein by reference).
10.23*	—	Form of Restricted Stock Agreement (two-year time vested for principal executive officer) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.3 to the Registrant’s Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.24*	—	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 and incorporated herein by reference).
10.25*	—	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 and incorporated herein by reference).
10.26*		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, 2015 and incorporated herein by reference).
10.27*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (as amended effective January 1, 2008), (filed as Exhibit 10.40 to the Registrant’s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.28*	—	Amendment to the Noble Energy, Inc. Change of Control Severance Plan for Executives dated effective February 1, 2011 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (Date of Report: February 1, 2011), filed February 4, 2011 and incorporated herein by reference).
10.29*	—	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 and incorporated herein by reference).
10.30*	—	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 and incorporated herein by reference).

10.31*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (effective December 7, 2016) filed herewith.
10.32*	—	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 and incorporated herein by reference).
10.33*	—	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 and incorporated herein by reference).
10.34*	—	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 and incorporated herein by reference).
10.35*	—	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 and incorporated herein by reference).
10.36	—	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 and incorporated herein by reference).
10.37	—	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 and incorporated herein by reference).
10.38	—	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 and incorporated herein by reference).
10.39	—	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 and incorporated herein by reference).
10.40*	—	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 and incorporated herein by reference).
10.41*	—	Retention and Confidentiality Agreement between Noble Energy, Inc. and Ted D. Brown, Senior Vice President, dated May 1, 2013 (filed as Exhibit 10.2 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013 and incorporated herein by reference).
10.42*	—	Amendment to Retention and Confidentiality Agreement between Noble Energy, Inc. and Ted D. Brown, Senior Vice President, effective as of February 24, 2014 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (Date of Report: February 19, 2014), filed February 25, 2014 and incorporated herein by reference).
10.43*	—	Retention and Confidentiality Agreement between Noble Energy, Inc. and Charles D. Davidson, Chairman and Chief Executive Officer, effective as of August 14, 2014 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (Date of Report: August 14, 2014), filed August 19, 2014 and incorporated herein by reference).
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
21	—	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 U.S.C. 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 U.S.C. 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 U.S.C. 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 U.S.C. Section 1350), filed herewith.
99.1	—	Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.2	—	Unaudited Pro Forma Financial Information for the year ended December 31, 2015, 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

* 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.

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
HH	Henry Hub index
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
NGL	Natural gas liquids
NYMEX	The New York Mercantile Exchange
OPEC	The Organization of Petroleum Exporting Countries
PSC	Production sharing contract
Tcf	Trillion cubic feet
US GAAP	United States generally accepted accounting principles
WTI	West Texas Intermediate index

DIRECTORS

David L. Stover ●
Chairman, President and Chief Executive Officer, Noble Energy, Inc.

Jeffrey L. Berenson ● ●
Chairman and Chief Executive Officer, Berenson & Company

Michael A. Cawley ● ●
President and Manager, The Cawley Consulting Group, LLC

Edward F. Cox ● ● ●
Chair, New York Republican State Committee

James E. Craddock ● ● ●
Former Chief Executive Officer, Rosetta Resources Inc.

Thomas J. Edelman ● ● ●
Managing Partner, White Deer Energy LP

Eric P. Grubman ● ●
Executive Vice President, National Football League

Kirby L. Hedrick ● ● ●
Former Executive Vice President, Phillips Petroleum Company

Scott D. Urban ● ● ●
Partner, Edgewater Energy LLC

William T. Van Kleef ● ●
Former Executive Vice President and Chief Operating Officer, Tesoro Corporation

Molly K. Williamson ● ● ●
Scholar with the Middle East Institute

Committee Membership

- Audit Committee
- Compensation, Benefits and Stock Option Committee
- Corporate Governance and Nominating Committee
- Environment, Health and Safety Committee

EXECUTIVE OFFICERS

David L. Stover
Chairman, President and Chief Executive Officer

Kenneth M. Fisher
Executive Vice President and Chief Financial Officer

Susan M. Cunningham
Executive Vice President, EHSR and New Frontiers

Gary W. Willingham
Executive Vice President, Operations

J. Keith Elliot
Senior Vice President, Eastern Mediterranean

Terry R. Gerhart
Senior Vice President, Global Operations Services

Arnold J. Johnson
Senior Vice President, General Counsel and Secretary

John T. Lewis
Senior Vice President, Corporate Development

Charles J. Rimer
Senior Vice President, U.S. Onshore

A. Lee Robison
Senior Vice President, Human Resources and Administration

Michael W. Putnam
Vice President, Exploration

GENERAL INFORMATION

Annual Meeting
The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 26, 2016, at 9:30 a.m. Central Time, at The Houstonian, 111 N. Post Oak Lane, Houston, Texas 77024. All stockholders are cordially invited to attend.

Form 10-K
The company's Annual Report on Form 10-K for the year ended on December 31, 2015, as filed with the Securities and Exchange Commission (SEC), is included in this report. Additional copies are available without charge upon request by writing to: Investor Relations, Noble Energy, Inc., 1001 Noble Energy Way, Houston, Texas 77070; via the company's website: www.nobleenergyinc.com; or via the SEC's website: www.sec.gov.

Noble Energy, Inc. Corporate Headquarters
1001 Noble Energy Way, Houston, Texas 77070
281.872.3100, www.nobleenergyinc.com

Investor Relations
Brad Whitmarsh, Vice President, Investor Relations
281.872.3100, investor_relations@nblenergy.com

Communications and Media Relations
Ben Dillon, Vice President, Communications and Government Relations, 281.872.3100, media@nblenergy.com

Independent Public Accountants
KPMG LLP

Transfer Agent and Registrar
Wells Fargo Bank, N.A., Shareowner Services,
P.O. Box 64854, St. Paul, MN 55164-0854
800.468.9716, www.shareowneronline.com

Common Stock Listed
New York Stock Exchange, Symbol - NBL

Forward-Looking Statements and Other Matters
This 2015 Annual Report to Stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 1A. Risk Factors. Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The SEC permits the optional disclosure of probable and possible reserves; however, we have not disclosed our probable and possible reserves in our filings with the SEC. In this publication, we refer to certain non-engineer reserve quantities associated with the Eastern Mediterranean, including the Tamar and Leviathan fields, and the SEC guidelines strictly prohibit us from including them in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosures and risk factors in our Form 10-K included in this report.

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