NOBLE ENERGY INC
Form 10-K
February 19, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-07964

NOBLE ENERGY, INC.	
(Exact name of registrant as specified in its charter)	
Delaware	73-0785597
(State of incorporation)	(I.R.S. employer identification number)
1001 Noble Energy Way	
Houston, Texas	77070
(Address of principal executive offices)	(Zip Code)
(281) 872-3100	
(Registrant’s telephone number, including area code)	
Securities registered pursuant to section 12(b) of the Act:	
Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ý Yes o No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes ý No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ý Yes o No
Indicate by check mark whether the registrant has submitted electronically 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). ý Yes o No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer 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 x	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
	(Do not check if a smaller reporting company)		

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).o Yes ý No
Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2014: $28.0 billion.
Number of shares of Common Stock outstanding as of December 31, 2014: 362,126,299.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the Registrant's definitive proxy statement for the 2015 Annual Meeting of Stockholders to be held on April 28, 2015, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2014, 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 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 embracing 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; US and international projects; and production mix among crude oil, natural gas and NGLs. Exploration success, along with development capital investment in the US and in international locations such as West Africa and the Eastern Mediterranean, has resulted in a visible lineup of major development projects which positions us for long-term future reserves, production and cash flow growth. Occasional strategic acquisitions of producing and non-producing properties, combined with the periodic divestment of non-core assets, have allowed us to achieve our objective of a well-diversified, growing portfolio. During 2014, we spent over $4.8 billion in oil and gas exploration and development activities.

Our portfolio is diversified between short-term and long-term projects, both onshore and offshore, domestic and international. Our organization and business model is focused on sustainable, high-return growth through effective major development project execution complimented by pursuit of exploration opportunities which can be monetized on a competitive discovery-to-production cycle. Our ability to deliver major development projects on schedule and within budget has provided a competitive and financial advantage in the industry.

However, the upstream oil and gas business is cyclical. During fourth quarter 2014, a significant decline in crude oil prices occurred which may result in deferral of some of our growth plans. We have taken steps to mitigate the impact on our business. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview, Operating Outlook and Liquidity and Capital Resources.

Onshore US assets provide a stable base of production along with high return, low risk development programs that deliver growth and accommodate a capital investment program that can be adjusted in response to ongoing changes in the economic environment. We continue to enhance project performance through technology and operational efficiency. Our long cycle offshore development projects, while requiring multi-year capital investment, are expected to offer attractive financial returns, and sustained production and cash flow.

We have operations in five core areas:

- the DJ Basin (onshore US);
- the Marcellus Shale (onshore US);
- the deepwater Gulf of Mexico (offshore US);
- offshore West Africa; and

These five core areas provide:

- almost all of our crude oil, natural gas and NGL production;
- visible growth from major development projects; and
- exploration opportunities.

l offshore Eastern Mediterranean.

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Our growth has been supported by a strong balance sheet and liquidity levels. We strive to deliver competitive returns and a growing dividend. Our annual cash dividends increased 89% in the last five years, from 36 cents per share in 2009 to 68 cents per share in 2014 (as adjusted for the 2 for 1 stock split during second quarter 2013). See Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Stock Performance Graph and Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2010-2014.

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 2014. Although these projects will require significant capital investments over the next several years, they typically offer long-life, sustained cash flows and attractive financial returns. 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]
· Gunflint (deepwater Gulf of Mexico)	· Cyprus (offshore Cyprus)
· Big Bend (deepwater Gulf of Mexico)	· Diega and Carla (offshore Equatorial Guinea)
· Dantzler (deepwater Gulf of Mexico)	
· Tamar Compression (onshore Israel) [3]	
· Tamar Southwest (offshore Israel) [3] [4]	

(1) Final investment decision has been made.
(2) Represents multiple ongoing development projects.
(3) See Update on Core Area – Israel, below.
(4) Regulatory approval for the project has been delayed. We recently petitioned the Israeli courts to expedite approval.

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.

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Proved Oil and Gas Reserves Proved reserves at December 31, 2014 were as follows:

Summary of 2014 Oil and Gas Reserves as of Fiscal-Year End
Based on Average 2014 Fiscal-Year Prices

	December 31, 2014 Proved Reserves			
	Crude Oil and Condensate	Natural Gas	NGLs	Total
Reserves Category	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe) [1]
Proved Developed				
United States	119	1,459	64	426
Equatorial Guinea	52	377	8	124
Israel	3	1,973	—	331
Total Proved Developed Reserves	174	3,809	72	881
Proved Undeveloped				
United States	117	1,345	49	390
Equatorial Guinea	13	236	7	59
Israel	—	443	—	74
Total Proved Undeveloped Reserves	130	2,024	56	523
Total Proved Reserves	304	5,833	128	1,404

(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 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. See Item 6. Selected Financial Data.

Our total proved reserves of 1,404 MMBoe as of December 31, 2014 remained essentially the same as December 31, 2013, as record production volumes and reserves associated with divested assets were replaced by extensions, discoveries and other additions. Our proved reserves are 58% US and 42% international, and the mix is 31% global liquids (crude oil and NGLs), 36% international natural gas, and 33% 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 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. We have had substantial exploration success onshore US, in the deepwater Gulf of Mexico, the Douala Basin offshore West Africa and the Levant Basin offshore Eastern Mediterranean, resulting in our significant portfolio of major development projects. We have exploration opportunities remaining in these areas and are also engaged in new venture activity in both the US and international locations. Our focus on exploration activities has created a sustainable exploration program. During 2014, we conducted exploration activities in domestic and international locations such as northeast Nevada, deepwater

Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean, and 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. In 2014, 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.

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IPO of Marcellus Shale Midstream Assets During third quarter 2014, our equity method accounted investee, CONE Gathering LLC (CONE Gathering), contributed a significant majority of its existing assets to a newly-formed master limited partnership, CONE Midstream Partners LP (CONE Midstream, CONE Midstream IPO). We own a 32.1% interest in CONE Midstream, which constructs, owns and operates natural gas midstream assets in support of our Marcellus Shale joint venture activities.

Atwater Valley Acquisition During second quarter 2014, we acquired working interests in 17 deepwater exploration leases in the Atwater Valley protraction area, deepwater Gulf of Mexico. We acquired a 50% working interest in 13 leases and an average 26% working interest in four leases.

Offshore Israel Assets In March 2014, we and our partners reached an agreement with the Israeli Antitrust Authority on various antitrust matters. As a result of the agreement, we agreed to divest the Tanin and Karish natural gas discoveries. We initiated an active program to locate a buyer and take other actions required to complete the plan to sell the assets. On December 23, 2014, we and our partners in the Leviathan field were advised by the Israel Antitrust Authority of its decision to not submit the agreement to the Antitrust Tribunal for final approval. See Update on Core Area – Israel, below.

Gabon Entry During third quarter 2014, we signed a Production Sharing Contract (PSC) with the Government of Gabon covering Block F15, located 140 kilometers off the coast of Gabon and covering over 670,000 gross acres. Under the terms of the PSC, we will be the operator with a 60% working interest.

Non-Core Divestiture Program Our non-core divestiture program is designed to generate organizational and operational efficiencies as well as cash for use in our capital investment program. Divestitures of non-core properties allow us to allocate capital and employee resources to higher-value and higher-growth areas. The program generated combined net proceeds of $2.4 billion during the last five years, including $321 million during 2014. In addition, we received a $204 million distribution of offering proceeds from the CONE Midstream IPO mentioned above. The proceeds from divestitures provide additional flexibility in the implementation of our international and deepwater Gulf of Mexico exploration and development programs and our horizontal drilling activities in the DJ Basin and Marcellus Shale. During 2014, we sold onshore US properties in the Piceance Basin, Tri-State and Powder River areas and our China assets.

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. Property Transactions.

Asset Impairments We recorded $500 million in impairment charges for 2014, including $336 million in fourth quarter 2014. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Update on Core Area – Israel Recent developments in the regulatory environment in Israel have had a significant impact on our future development plans. We plan to complete the Ashdod onshore terminal (AOT) compression project in the first half of 2015 and continue the sale of natural gas from the Tamar field to existing domestic customers. However, as discussed below, further investments in the expansion of Tamar, as well as the initial development of Leviathan, will be driven by achievement of regulatory certainty in Israel.

Potential for Future Growth and Development The quantity of discovered resources at Tamar and Leviathan have positioned Israel to meet domestic energy needs for years to come as well as become a significant natural gas exporter. Multiple regional markets are emerging and domestic demand can increase significantly in the future as existing coal burning facilities are either converted to natural gas or replaced by more efficient natural gas fired combined cycle power stations, and industrial and commercial applications are realized. In addition to producing natural gas to accommodate domestic and regional consumption, we believe our Eastern Mediterranean export projects would be well positioned to supply demand for natural gas beyond domestic and regional markets.

We are committed to the prudent and efficient development of both Tamar and Leviathan. We have engaged in engineering design and planning work for a potential first phase of development at Leviathan as well as follow-on developments at Tamar. Potential Leviathan development scenarios have included options that would require multi-billion dollar investments and span a number of years from project sanction to first production.

We have worked with the Israeli government to obtain support for the Leviathan development project, a complex, costly project with numerous political, financial and execution risks. We have also supported the efforts of our

Leviathan partners to obtain appropriate financing for their share of development costs, and we have sought other arrangements with experienced industry participants to ensure the required technical support for the execution of the project.

On December 2, 2012, we and our existing partners announced that we had agreed in principle on a proposal to sell a working interest in the Leviathan licenses to Woodside Energy Ltd. (Woodside). During 2013, we continued discussions with Woodside and, in February 2014, we signed a non-binding memorandum of understanding (MOU) for the sale of an interest in Leviathan to Woodside. However, in May 2014, we announced that negotiations between the parties had terminated. One factor contributing to Woodside's withdrawal was their inability to reach agreement with the Israeli government on various export tax issues.

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Despite the withdrawal of Woodside, we moved forward with development plans for Leviathan Phase 1 and adopted a design utilizing a 1.6 Bcf/d floating production, storage and offloading vessel (FPSO). Technical design work for Leviathan Phase I became well advanced, and in 2014, we submitted the Phase 1 Plan of Development to the Ministry of National Infrastructures, Energy and Water Resources. We also engaged in marketing efforts and negotiated regional natural gas sales agreements with third parties to various degrees of maturity. However, regulatory uncertainty has delayed the consummation of non-binding Letters of Intent (LOIs) or natural gas sales and purchase agreements (GSPAs) and some of these agreements have expired. Therefore, our specific development plan may no longer be feasible; future development plans will require a technical design concept appropriate for the natural gas sales volumes ultimately contracted.

Increasingly Uncertain Regulatory Environment in Israel We have cooperated with the Israeli government on all significant matters relating to our exploration and development plans for offshore Israel. However, the regulatory environment in Israel has become increasingly challenging and uncertain. Laws, regulations and guidelines have been modified, sometimes with retroactive impacts, and as a result the investment climate has become unpredictable. Timing of approval for development plans has been delayed, and consequently our ability to make significant, long-term investment decisions has become increasingly difficult.

For example:

- Changes in Tax Law In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011 (Petroleum Profits Law), which imposed additional income tax on crude oil and natural gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs.

On March 26, 2014, the Ministry of Finance issued a memorandum indicating its intent to amend the Petroleum Profits Law to regulate the method of taxing petroleum export transactions, and, in particular, exports of natural gas. Among other things, this action had a detrimental effect on our ability to reach commercial terms with Woodside, leading to a termination of the MOU.

- Natural Gas Policy In September 2012, the Interministerial Committee to Examine Government Policy Regarding the Natural Gas Industry in Israel (the Interministerial Committee) issued final recommendations regarding a government policy for developing Israel’s natural gas economy. The recommendations included, among others, material restrictions on our ability to monetize our natural gas discoveries. The recommendations approved by the Israeli government included further limitations on exports of natural gas than were recommended by said committee. See Regulations – Israel’s Natural Gas Policy, below.
- Israel Antitrust Authority The Israeli Antitrust Commissioner (Commissioner) has intervened regarding the terms used in long-term contracts with certain natural gas customers; contended that the original acquisition agreement for the Leviathan acreage is an illegal restrictive arrangement; and, most recently, reversed a decision to submit a previously-agreed consent decree on certain antitrust matters (Consent Decree) to the Israeli Antitrust Tribunal for approval. Acting in good faith upon the Consent Decree, we consented to divest our Tanin and Karish natural gas discoveries and have been in discussions with potential purchasers. We believed that the Consent Decree matter had been resolved some time ago and had received recent assurances from the Antitrust Authority that approval was forthcoming. However, on December 23, 2014, we and our partners in the Leviathan field were advised by the Israel Antitrust Authority of its decision to not submit the Consent Decree to the Antitrust Tribunal for final approval. We requested an oral hearing with the Antitrust Authority, which took place on January 27, 2015, and await final disposition. See Regulations – Israel Antitrust Authority, below.
- Delay in Development Plan Approval We have worked with the Israeli government for some time to obtain regulatory approval for the Tamar Southwest development plan, and recently petitioned the Israeli courts to expedite the needed approvals.
- Pricing Disputes The Public Utility Authority (PUA) has amended its own pricing formulas to impact pricing of natural gas in the Israeli market. These actions created pricing disputes between natural gas sellers and buyers. In addition, there have been threats of price controls.
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Maritime Zones Law Bill The Israeli government has advanced a Maritime Zones Law bill that may adversely impact the ability to conduct oil and gas exploration and production activities in our offshore leases and licenses.

Changes in fiscal regimes and tax policies have material, long-term impacts on our business strategy, making it difficult to formulate and execute capital investment programs. The implementation of new, or modification of existing, laws or regulations, delays in approvals, and increasing tax costs disrupt our business plans and adversely impact our operations. In addition to the loss of a potential strategic partner for the Leviathan development, we have been delayed in negotiating project financing arrangements due to the uncertainty of the project. Furthermore, delay of the Tamar Southwest development could have a negative impact on our ability to achieve long-term reliability and redundancy for the overall Tamar project.

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Stable fiscal and regulatory regimes are imperative. However, the upcoming March 2015 general elections in Israel are likely to delay resolution of all pending issues until a new government is in place. We may be unable to move forward with our major development projects without the following:

- Approval of final GSPAs with off-takers, to support financing arrangements;
- Clear, economically viable tax rulings, including export tax rulings;
- Export approval with reasonable export allocations;
- Approvals of Plans of Development;
- Acceptable resolution of Leviathan and other pending matters with the Israeli Antitrust Authority;
- Timely permitting;
- Prompt decisions regarding pipeline onshore landing sites;
- Stability clauses and protection from changes in laws and regulations;
- Stable fiscal and contract terms that allow for financial returns that are appropriate to support long-term investment by a global exploration and production company; and
- Other relevant regulatory terms essential to offshore crude oil and natural gas exploration and production.

The resolution of the above items, and greater certainty with respect to Israeli fiscal and regulatory matters, is required. See also Item 1A. Risk Factors.

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 61% of 2014 total consolidated sales volumes and 58% of total proved reserves at December 31, 2014. Approximately 57% of the proved reserves in the US are natural gas, 29% are crude oil and condensate and 14% are NGLs.

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

	Year Ended December 31, 2014 Sales Volumes				December 31, 2014 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	50	206	17	101	198	1,051	78	451
Marcellus Shale	1	262	5	49	4	1,668	32	314
Deepwater Gulf of Mexico	15	14	1	18	32	43	3	42
Other Onshore US	1	36	—	8	2	42	—	9
Total	67	518	23	176	236	2,804	113	816

Wells drilled in 2014 and productive wells at December 31, 2014 for our US operating areas were as follows:

	Year Ended December 31, 2014 Gross Wells Drilled or Participated in (1)	December 31, 2014 Gross Productive Wells
DJ Basin	468	8,598
Marcellus Shale	179	441
Deepwater Gulf of Mexico	4	13
Other Onshore US	—	934
Total	651	9,986

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

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Locations of our onshore US operations as of December 31, 2014 are shown on the map below:

DJ Basin With the advent of horizontal drilling technology, the DJ Basin is now recognized by many industry analysts as a premier US crude oil resource play and is a key driver of our production and cash flow growth. Our position in the core area extends over 600,000 net acres.

The DJ Basin contributed an average of 101 MBoe/d of sales volumes, representing approximately 35% of total consolidated sales volumes in 2014, with approximately 66% being crude oil and NGLs, and represented approximately 32% of total proved reserves at December 31, 2014.

2014 Activity Over the past year, we focused our drilling and development activity on Integrated Development Plan (IDP) areas, allowing us to consolidate processing and handling infrastructure across large areas (typically 30,000 to 80,000 acres). With this approach, we construct multi-well horizontal drilling pads and centralized processing facilities (CPFs) to minimize our surface use. The drilling pads and CPFs facilitate efficient execution of operations by reducing our 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 our production growth by constructing and expanding our infrastructure across the DJ Basin. In the first half of 2015, we will begin operation of the Keota plant, our second natural gas processing plant in northern Colorado, to support our East Pony IDP, which will provide additional capacity to support continued development in this part of the basin.

During 2014, we remained focused on horizontal drilling activity with continued growth from new wells brought online and expanded infrastructure. We accelerated our extended reach lateral well program to approximately 32% of our wells drilled in 2014. During the year, we spud 303 horizontal wells, of which 96 were extended reach lateral wells, and 310 wells initiated production. We also participated in approximately 160 non-operated development wells during 2014. We are currently running a four rig program.

Our 2014 DJ Basin development program resulted in net additions/revisions to proved reserves of approximately 39 MMBoe, approximately 62% of which are crude oil and NGLs.

Marcellus Shale The Marcellus Shale represents our second onshore US core area. 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.

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We operate the wet gas (natural gas containing more liquid hydrocarbons) development area in Moundsville, Shirley and Oxford, West Virginia, while CONSOL operates the dry gas (natural gas containing less liquid hydrocarbons) development area. During 2014, the joint venture drilled 179 wells. Noble drilled 91 wells with an average lateral length per operated well of 8,000 feet, which is more than 1,000 feet longer than the previous year average and 3,000 feet longer than the 2012 average. The joint venture initiated production on 129 wells.

Currently, two operated drilling rigs are running in the wet gas area and four non-operated rigs are running in the dry gas area. We and our partner continue to have discussions on the level of joint venture investment in 2015.

Utilizing an IDP concept, modeled after the DJ Basin, we have begun to realize cost efficiencies through multi-well pads, central facilities and efficient liquids infrastructure that enables 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 2013 as the first operated IDP location, is in the core operating area with water and marketing infrastructure in place to support further development.

We and CONSOL also operate CONE Gathering, which constructs, owns and operates midstream infrastructure servicing our joint production, and is the general partner controlling interest in CONE Midstream. See Midstream IPO, below.

The Marcellus Shale contributed an average of 296 MMcfe/d of sales volumes and represented approximately 17% of total consolidated sales volumes in 2014 and approximately 22% of total proved reserves at December 31, 2014. Our 2014 Marcellus Shale development program resulted in net additions/revisions to proved reserves of approximately 79 MMBoe, approximately 17% of which are crude oil and NGLs.

Midstream IPO On September 24, 2014, 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. As a result of the transaction, we own a 32.1% interest in CONE Midstream, which we account for using the equity method of accounting. We received a $204 million distribution of offering proceeds from CONE Gathering.

Northeast Nevada Exploration Prospect   We have an active global new venture process focused on identifying additional exploration opportunities with reasonable entry cost, significant running room and the potential to become a new core area. In the onshore US, this effort has captured a 370,000 net acre position (66% fee acreage and remainder federal acreage) in northeast Nevada, prospective for crude oil exploration, which we identified through basin scale reconnaissance and innovative geoscience concepts. We are currently analyzing results from our first four exploratory vertical wells and may conduct additional production tests.

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 3% of total consolidated sales volumes in 2014 and approximately 1% of total proved reserves at December 31, 2014. During 2014, we sold various non-core onshore properties and continue to evaluate divestment opportunities. We are in the process of divesting certain of our properties located in the DJ Basin, outside of our core DJ Basin operating area. See Acquisition and Divestiture Activities – Non-Core Divestiture Program above.

During 2014, we recorded impairments of certain non-core onshore US properties. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

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Deepwater Gulf of Mexico   Locations of our operations in the deepwater Gulf of Mexico as of December 31, 2014 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 today the deepwater Gulf of Mexico is one of our five core operating areas. Our focus is on high-impact opportunities with the potential to provide significant medium- and long-term growth.

We have several producing fields, ongoing development projects and a substantial inventory of exploration opportunities. We currently hold leases on 143 deepwater Gulf of Mexico blocks, representing approximately 59,000 net developed acres and approximately 465,000 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 6% of total consolidated sales volumes in 2014 and 3% of total proved reserves at December 31, 2014.

2014 Impairment Expense

During 2014, we recorded impairment expense of $350 million, $325 million during fourth quarter 2014, related to deepwater Gulf of Mexico properties. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

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, high value tie-back opportunities. These prospects are subject to an ongoing technical maturation process and may or may not emerge as drillable options.

The Atwood Advantage drillship mobilized to the Gulf of Mexico and was used in the 2014 drilling plan which included various exploration, appraisal and well completion activities.

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. Additional exploration and appraisal drilling will be required to test the remaining resource potential.

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Atwater Valley During 2014, we acquired working interests in 17 deepwater exploration leases in the Atwater Valley protraction area, providing further opportunities to expand our exploration portfolio. We acquired a 50% working interest in 13 leases and an average 26% working interest in four leases. In third quarter 2014, we participated with a 50% non-operated working interest in the Bright prospect, which was drilled on Atwater Valley Block 362 to a total depth of 13,500 feet. The exploratory well reached the targeted Upper and Middle Miocene objectives and was subsequently plugged and abandoned as it did not encounter hydrocarbons.

Madison (Mississippi Canyon 479; 60% operated working interest) During fourth quarter 2014, we drilled an exploratory well at the Madison prospect. The well was drilled to a total depth of 16,859 feet, reaching the targeted Upper and Middle Miocene objectives, but did not encounter commercial quantities of hydrocarbons. The well has been plugged and abandoned.

Ongoing Major Development Projects

Rio Grande (Mississippi Canyon Block 698, 699, 738 and 782) The Rio Grande area represents several exploration successes in the deepwater Gulf of Mexico. Big Bend (54% operated working interest) is a 2012 crude oil discovery, Troubadour (60% operated working interest) is a 2013 natural gas discovery, and Dantzler (45% operated working interest) is a 2013 crude oil discovery.

A co-development project is underway for the Big Bend and Dantzler crude oil discoveries. During 2014, we signed a production handling agreement for tie back to the Thunder Hawk semi-submersible production facility. We expect to continue development of these projects during 2015. First production for Big Bend is targeted for fourth quarter 2015, and first production for Dantzler is targeted for first quarter 2016.

During 2014, we announced final well results at the Dantzler-2 appraisal well, which encountered 122 net feet of crude oil pay in two high-quality Miocene reservoirs. The well was drilled to a total depth of 18,210 feet in 6,600 feet of water.

We are currently evaluating a number of development options for Troubadour including subsea tieback to existing infrastructure.

Gunflint (Mississippi Canyon Block 948; 26% operated working interest) Gunflint is a 2008 crude oil discovery. We expect to continue development of this project in 2015. Development is on track utilizing a two-well subsea tieback to the Gulfstar 1 spar platform, and topsides equipment fabrication is underway for planned 2015 installation. 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.

Raton (Mississippi Canyon Block 248; 67% operated working interest) is a 2006 natural gas discovery and has been producing since 2008. Raton is currently shut in waiting on completion of third party platform maintenance.

South Raton (Mississippi Canyon Block 292; 79% operated working interest) is a 2008 crude oil discovery and began producing in 2012. During 2013, South Raton development in the deepwater Gulf of Mexico was shut-in due to mechanical issues. During 2014, the well was brought back online and, as part of our remediation plan, granted a 180 day Suspension of Operations (SOO) by the Bureau of Safety and Environmental Enforcement (BSEE) to conduct remediation activities. During 2014, we recorded an impairment of South Raton.

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

Ticonderoga (Green Canyon Block 768; 50% non-operated working interest) is a 2004 crude oil discovery and began producing in 2006. The project currently includes four producing wells.

Lorien (Green Canyon Block 199; 60% operated working interest) is a 2003 crude oil discovery and began producing in 2006. The project currently includes one producing well.

These properties are connected to existing infrastructure through subsea tiebacks.

International

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

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During 2014, we continued to advance our major development projects, including the Tamar field compression project and the Leviathan development project. 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. Large acreage positions in West Africa and the Eastern Mediterranean could provide further exploration opportunities. International operations accounted for 39% of total consolidated sales volumes in 2014 and 42% of total proved reserves at December 31, 2014. International proved reserves are approximately 86% natural gas and 14% crude oil and condensate.

Operations in Cyprus, Equatorial Guinea, Gabon, and Sierra Leone 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 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, 2014 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, 2014				December 31, 2014			
	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	33	243	—	74	65	613	15	183
Israel	—	231	—	39	3	2,416	—	405
China [1]	2	—	—	2	—	—	—	—
Total International	35	474		115	68	3,029	15	588
Equity Investee	2	—	5	7	—	—	—	—
Total	37	474	5	122	68	3,029	15	588
Equity Investee Share of Methanol Sales (MMgal)				130				

[1] On June 30, 2014, we closed the sale of our China assets.

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There were no international wells drilled in 2014. Productive wells at December 31, 2014 in our international operating areas were as follows:

	December 31, 2014 Gross Productive Wells
International	
Equatorial Guinea	25
Israel	8
North Sea	6
Total International	39

West Africa (Equatorial Guinea, Cameroon, Sierra Leone 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, two blocks offshore Sierra Leone, and one block offshore Gabon. Equatorial Guinea, the only producing country in our West Africa segment, accounted for approximately 25% of 2014 total consolidated sales volumes and 13% of total proved reserves at December 31, 2014. We held approximately 118,000 net developed acres and 30,000 net undeveloped acres in Equatorial Guinea, 695,000 net undeveloped acres in Cameroon, 414,000 net undeveloped acres in Sierra Leone and 403,000 net undeveloped acres in Gabon at December 31, 2014.

Locations of our operations in Equatorial Guinea and Cameroon, as of December 31, 2014 are shown on the map below:

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Aseng Project 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 13 MBoe/d, net, during 2014.

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 Project Alen, is a natural gas and condensate field primarily on Block O (45% operated working interest), offshore Equatorial Guinea, which includes three horizontal wells connected to a production platform that utilizes the Aseng FPSO for storage and offloading. Alen has been producing since 2013. During 2014, we completed the 1P sidetrack well to enhance production efficiencies. Alen produced approximately 11 MBoe/d, net, during 2014.

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 50 MBoe/d, net, during 2014.

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. The methanol plant is scheduled for turnaround activities in 2015. Alba Plant sells its LPG products and condensate at our marine terminal at prevailing market prices. We sell our share of condensate produced in the Alba field under short-term contracts at market-based prices.

The execution phase of the Alba field B3 compression project began in early 2013. We expect to continue working on this project during 2015, with an anticipated completion date mid-2016.

Other Block O & I Projects During 2014 we acquired 3D seismic data across Blocks O and I and are currently processing the results which will aid in efficiently producing the Aseng and Alen fields as well as potentially advancing other regional exploration and development opportunities, including Diega (Block I), Carla (Block O), and Carmen (Block O).

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 (66.67% operating 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. We are reprocessing 3D seismic data over our YoYo mining concession and plan to drill the Cheetah exploration prospect in the second half of 2015.

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, and the YoYo discovery, offshore Cameroon. 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.

Sierra Leone We participate in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million gross undeveloped acres, in which we have a non-operated 30% working interest. We are currently evaluating recently reprocessed seismic data over the blocks.

Gabon During 2014, we expanded our exploration portfolio by signing a PSC with the Government of Gabon. We are the operator of Block F15 (60% working interest), an undeveloped, ultra-deep water area, covering over 670,000 gross acres. The PSC includes a four-year seismic commitment and an option for exploration drilling. The exploration phase is underway and we are currently conducting an environmental impact assessment and considering options for shooting and acquiring 3D seismic data.

See also Item 8. Financial Statements and Supplementary Data – Note 5. Capitalized Exploratory Well Costs.
Eastern Mediterranean (Israel and Cyprus)   The Eastern Mediterranean is one of our core operating areas, where we have had eight consecutive natural gas discoveries in recent years. See Update on Core Area – Israel, above.

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Israel, the only producing country in our Eastern Mediterranean core area, accounted for 13% of 2014 total consolidated sales volumes and 29% of total proved reserves at December 31, 2014. Our leasehold position in the Eastern Mediterranean includes six leases and five licenses operated offshore Israel and one license operated offshore Cyprus. We hold approximately 80,000 net developed acres and 296,000 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, 2014 are shown below:

Domestic Natural Gas Demand   As the Israeli economy continues to grow, so does the demand for natural gas, used primarily for electricity generation. 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 GSPAs with domestic customers. See International Marketing Activities and Delivery Commitments, below.

Natural Gas Export   As discussed below, we have made significant natural gas discoveries in the Eastern Mediterranean. We expect that these discoveries can be used to satisfy growing domestic demand as well as provide significant export potential. Eastern Mediterranean export projects would be well positioned to supply growing regional and global natural gas demand.

During 2014, we entered into LOIs for the export of natural gas to Egypt and Jordan.We also entered into a natural gas sales and purchase agreement with the Palestine Power Generation Company, Arab Potash Company and Jordan Bromine Company. We negotiated the LOIs to various degrees of maturity, some to full maturity. However, the emerging regulatory uncertainty has delayed the consummation of LOIs or GSPAs for regional natural gas sales. In the meantime, we continue to maintain active discussions with our potential customers in an effort to maintain our ability to eventually conclude negotiations and execute GSPAs. See Regulations – Israel's Natural Gas Policy, below.

Tamar Natural Gas Projects   Just over four years from discovery, the Tamar project began production in March 2013 with capable peak flow rates of approximately 1.1 Bcf/d, gross, to support seasonal high demand periods. The natural gas flows from the Tamar field through the world's longest subsea tieback, more than 90 miles to the Tamar platform, and then to the AOT. Tamar is a technical and commercial milestone that contributes significantly to our production profile. Production from Tamar averaged 219 MMcf/d, net, for 2014.

During 2014, we advanced the Tamar compression project, which will expand field production capacity by adding compression at the AOT. Compression is targeted to increase deliverability to a peak of 1.2 Bcf/d, gross, beginning in mid-2015.

Also during 2014, we continued to work with the Israeli government 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. Timely development of Tamar Southwest is important to achieve long-term reliability and redundancy for our overall Tamar project. Although the development project was sanctioned in 2013, continuing delays in securing regulatory approvals have placed the project at risk of delay. We recently petitioned the Israeli courts to expedite the needed approvals.

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 The 2010 Leviathan discovery (39.66% operated working interest) is the largest discovery in our history. Due to Leviathan's size, full field development is expected to require several development phases. During 2014, the Leviathan licenses were converted to Development and Production Leases and we submitted the Plan of Development to the Ministry of National Infrastructures, Energy and Water Resources. The development plan is expected to serve both domestic demand and export.

Timing of project sanction, which we have been targeting for 2015, depends on final resolution of antitrust and other regulatory matters, as well as execution of GSPAs, which will be subject to, among other conditions, the receipt of regulatory approvals. Project financing will also be required. We are engaged with the governments of the US, Israel, Jordan and Egypt on this project.

We have been working towards sanction of Leviathan Phase I based on the agreement we and our partners reached with the Israeli Antitrust Authority on various antitrust matters earlier in 2014. However, on December 23, 2014, we and our partners were advised by the Israel Antitrust Authority of its decision to not submit the Consent Decree to the Antitrust Tribunal for final approval. This is a matter that we believed was resolved some time ago and we had received recent assurances from the Antitrust Authority that approval was forthcoming. We requested an oral hearing with the Antitrust Authority, which took place on January 27, 2015, and await final disposition. See Update on Core Area – Israel, above.

Karish and Tanin We have been working towards a sale of the Karish and Tanin discoveries based on the agreement we and our partners reached with the Israeli Antitrust Authority on various antitrust matters earlier in 2014. However, the reversal of the Antitrust Authority of its decision to submit the Consent Decree to the Antitrust Tribunal for final approval has had a negative impact on our ability to close a sale of these discoveries. See Update on Core Area – Israel, above.

Other Discoveries Offshore Israel We and our partners submitted a development plan for the Dalit field (36% operated working interest), a 2009 natural gas discovery. Development would include a tie-in 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.

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We are reviewing development scenarios 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.

Future Investment Further investments in the expansion of Tamar, as well as the initial development of Leviathan, will be driven by achievement of regulatory certainty in Israel. See Update on Core Area – Israel, above.

Cyprus Project (Offshore Cyprus) In May 2014, our application for renewal of the PSC for two additional years was approved. We are currently evaluating development scenarios for Block 12 (70% operated working interest) and plan to submit a plan of development to the Cypriot government in 2015. There is also potential for a farm-out arrangement of our working interest.

See also Item 8. Financial Statements and Supplementary Data – Note 5. Capitalized Exploratory Well Costs.

Other International

Our other international operations accounted for 1% of total consolidated sales volumes for 2014 and less than 1% of total proved reserves at December 31, 2014.

Falkland Islands We currently operate the Northern and Southern Area licenses with a 35% working interest in approximately 10 million gross acres located south and east of the Falkland Islands. We continue to acquire and process 3D seismic information for both licenses and anticipate exploratory drilling operations to begin in mid-2015. In third quarter 2014, based on the results of seismic interpretation conducted on the Scotia exploratory well which was drilled in 2012, we concluded that the Scotia prospect was not economically viable and recorded dry hole cost.

China In June 2014, we sold our China assets. See Item 8. Financial Statements and Supplementary Financial Data – Note 3. Property Transactions.

Nicaragua After evaluation of the Paraiso exploratory well results and the regional geology in the Tyra and Isabel blocks, we notified the Nicaraguan government of our intention to relinquish both concessions in the first half of 2015.

North Sea In 2012 and 2013, we sold the working interests in many of our non-operated North Sea properties. During 2014, the remaining unsold non-operated properties were transferred from assets held for sale as we were not able to locate a buyer. The decommissioning of our remaining North Sea portfolio is planned to begin in mid-2015. During 2014, we recorded an impairment of the MacCulloch field. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Proved Reserves Disclosures

Internal Controls Over Reserves Estimates Our policies 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.

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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 2014 reserves estimates.

Based on reasonable certainty of reservoir continuity of the Niobrara and Marcellus Shale formations, 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 2014, 2013, and 2012, we retained NSAI to perform audits of proved reserves. The reserves audit for 2014 included a detailed review of eight of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 79.8% of US proved reserves and 99.4% of international proved reserves (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. The reserves audit for 2012 included a detailed review of eight of our major fields and covered approximately 93% of total proved reserves.

In connection with the 2014 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, 2014, 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.

The fields audited by NSAI are chosen in accordance with Company guidelines and result in the audit of a minimum of 80% of our total proved reserves. The fields are chosen by the Senior Vice President – Corporate Development and are reviewed by senior management and the Audit Committee of our Board of Directors. Our practice is to select fields for audit based on size. This process results in the audit of fields that meet a minimum reserve quantity threshold, newly sanctioned development projects, and certain fields selected on a rotational basis.

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, 2014, on a quantity basis, the NSAI field estimates ranged from 27 MMBoe or 9% above to 13 MMBoe or 4% 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, 2014 were, in the aggregate, approximately 16 MMBoe, or 1%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2014, our PUDs totaled 130 MMBbls of crude oil and condensate, 2.0 Tcf of natural gas, and 56 MMbbls of NGLs for a total of 523 MMBoe.

PUDs Locations We have several significant ongoing development projects which are in various stages of completion. PUDs are located as follows at December 31, 2014:

- 183 MMBoe in the DJ Basin. Based on our current inventory of identified horizontal well locations and our anticipated rate of drilling activity, we expect these PUDs to be converted to proved developed reserves within a five-year period;

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- 179 MMBoe in the Marcellus Shale. Based on our current inventory of identified horizontal well locations and our anticipated rate of drilling activity, we expect these PUDs to be converted to proved developed reserves within a five-year period;
- 28 MMBoe in the deepwater Gulf of Mexico;
- 59 MMBoe in the Alba field, offshore Equatorial Guinea, 57 MMBoe 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 2016; and
- 74 MMBoe in Israel primarily in the Tamar and Tamar Southwest fields. PUDS of 32 MMBoe relate to the Tamar Southwest field, which is awaiting government approval of the development plan.

The above fields represent almost 100% of total PUDs. PUDs include no material amounts, except the Alba field PUDs, which have remained undeveloped for five years or more since initial disclosure.

Changes in PUDs   Changes in PUDs that occurred during the year were due to:

(MMBoe)	United States	Equatorial Guinea	Israel	China	Total
Proved Undeveloped Reserves Beginning of Year	425	58	72	2	557
Revisions of Previous Estimates	(14)	1	2	—	(11)
Extensions, Discoveries and Other Additions	95	—	—	—	95
Purchase of Minerals in Place	—	—	—	—	—
Sale of Minerals in Place	(1)	—	—	(2)	(3)
Conversion to Proved Developed	(115)	—	—	—	(115)
Proved Undeveloped Reserves End of Year	390	59	74	—	523

United States

- downward revisions of 14 MMBoe, primarily due to planned reduction in pace of DJ Basin drilling activity due to lower commodity price outlook;
- additions of 26 MMBoe in the DJ Basin horizontal drilling program; 59 MMBoe in the Marcellus Shale horizontal drilling program; and 10 MMBoe in the Gulf of Mexico; and
- conversion of 115 MMBoe into proved developed reserves attributable to ongoing development in the DJ Basin (24% of year end 2013 PUD volumes converted) and Marcellus Shale (34% of year end 2013 PUD volumes converted).

Equatorial Guinea

- positive revisions of 1 MMBoe due to performance revisions for the Alba field.

Israel

- positive revisions of 2 MMBoe due to performance revisions for the Tamar field.

China

- sales of 2 MMBoe due to the sale of our China assets in June 2014.

Development Costs   Costs incurred to advance the development of PUDs were approximately $2.0 billion in 2014, $1.0 billion in 2013, and $1.8 billion in 2012. A significant portion of costs incurred in 2014 related to the DJ Basin and Marcellus Shale development projects.

Estimated future development costs relating to the development of PUDs are projected to be approximately $2.2 billion in 2015, $1.8 billion in 2016, and $1.7 billion in 2017. 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 2019. 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 2015 - 2019.

PUDs with Negative PV10 At December 31, 2014, we had 75 PUD well locations with negative present worth discounted at 10% based on constant prices and costs in our Marcellus Shale core area. Net quantities totaled 0.2

MMBbl of crude oil and condensate, 177 Bcf of natural gas, and 2.2 MMBbl of NGLs. These locations represented approximately 6% of both total PUD locations and total PUD quantities at December 31, 2014. Although these reserves had a negative present worth 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

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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 – 2015 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.

Other Reserves Information   Since January 1, 2014, no crude oil or natural gas reserves information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (EIA) of the US Department of Energy. We file Form 23, including reserves and other information, with the EIA.

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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, 2014							
United States							
DJ Basin	18,209	75,039	6,072	$87.86	$4.11	$34.51	$6.30
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	5.50
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	$5.42
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	$4.92
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	6.13
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	$5.40
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	
Year Ended December 31, 2012							
United States							
DJ Basin	11,647	70,959	4,625	$89.41	$2.67	$35.50	$4.45
Other US	6,401	89,308	1,365	104.30	2.57	34.92	8.00
Total US	18,048	160,267	5,990	94.69	2.61	35.36	6.04
Equatorial Guinea							
Alba Field [(2)]	4,439	86,162	—	107.08	0.27	—	2.79
Aseng Field	7,544	—	—	111.93	—	—	4.88

Total Equatorial Guinea	11,983	86,162	—	110.14	0.27	—	3.39
Mari-B Field (Israel)	—	36,806	—	—	4.85	—	3.23
China	1,540	—	—	114.54	—	—	10.33
Total Consolidated Operations	31,571	283,235	5,990	101.52	2.19	35.36	$5.09
Equity Investee (3)	648	—	2,108	104.56	—	69.14	
Total Continuing Operations	32,219	283,235	8,098	$101.58	$2.19	$44.15	

(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.

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(2) Natural gas from the Alba field is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. Sales to these plants are based on a Btu equivalent and then converted to a dry gas equivalent volume. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes produced by the LPG plant are included in the crude oil information.

(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, 2014, 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, 2014 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	6,532	5,808.9	3,454	2,726.2	9,986	8,535.1
Equatorial Guinea	5	2.0	20	7.6	25	9.6
Israel	—	—	8	3.2	8	3.2
North Sea	5	0.7	1	0.2	6	0.9
Total	6,542	5,811.6	3,483	2,737.2	10,025	8,548.8

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, 2014 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore	1,249	833	1,200	735
Offshore	115	59	691	465
Total United States	1,364	892	1,891	1,200
International				
Equatorial Guinea	284	118	81	30
Falkland Islands	—	—	9,921	3,473
Cameroon	—	—	1,084	695
Israel	185	80	679	296
Cyprus	—	—	663	464
North Sea	6	1	14	2
Sierra Leone	—	—	1,380	414
Nicaragua [1]	—	—	1,931	1,545
Gabon	—	—	671	403
Total International	475	199	16,424	7,322
Total	1,839	1,091	18,315	8,522

(1) Represents acreage we expect to relinquish to the Nicaraguan government in the first half of 2015.

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.

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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,					
	2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US [1]	294	140	253	196	87	57
Deepwater Gulf of Mexico	53	42	127	72	19	9
Equatorial Guinea	55	19	—	—	—	—
Israel [2]	395	178	99	47	—	—
Cyprus [2]	—	—	663	464	—	—
Cameroon [3]	916	611	—	—	—	—
Sierra Leone [2]	1,380	414	—	—	—	—
Nicaragua [4]	1,931	1,545	—	—	—	—
Total	5,024	2,949	1,142	779	106	66

(1) Represents acreage that will expire if no further action is taken to extend. Approximately 91% of the acreage is located in core areas where we currently expect to continue development activities and/or extend the lease terms.

(2) Represents acreage that will expire if no further action is taken to extend. We currently intend to extend the leases prior to expiration in accordance with license terms. See also Regulations – Israel Natural Gas Policy and Israel Antitrust Authority, below.

(3) Represents acreage that will expire if no further action is taken to extend. The acreage represents the Tilapia PSC. We intend to formally request an extension of the lease during first quarter 2015; however, the extension timeline could vary and it is therefore unknown what percentage of acreage will be relinquished in 2015.

(4) Represents acreage that we expect to relinquish to the Nicaraguan government in the first half of 2015.

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, 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
Year Ended December 31, 2012							
United States	8.1	2.3	10.4	457.5	—	457.5	467.9
Equatorial Guinea	—	—	—	2.3	—	2.3	2.3
Cameroon	—	0.5	0.5	—	—	—	0.5
Israel	—	—	—	3.2	—	3.2	3.2

China	—	—	—	1.7	—	1.7	1.7
Total	8.1	2.8	10.9	464.7	—	464.7	475.6

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In addition to the wells drilled and completed in 2014 included in the table above, wells that were in the process of drilling or completing at December 31, 2014 were as follows:

	Exploratory[1]		Development[2]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	9	7.8	250	117.4	259	125.2
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	28	16.9	250	117.4	278	134.3

(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 Tanin and Karish exploratory wells which have been classified as assets held for sale as of December 31, 2014.

See Item 8. Financial Statements and Supplementary Financial Data – Note 5. 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 Helix Well Containment group, 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 placed 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 2014 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 with a remaining term through May 2015. 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.

Our North Sea crude oil production is transported by tanker and sold on the spot market. In China, prior to the sale of our China assets, we sold crude oil into the local market through pipelines under a long-term contract at market-based prices.

Delivery Commitments Some of our natural gas sales contracts specify the delivery of fixed and determinable quantities.

Domestic Natural Gas Sales We may use long-term sales agreements to provide flow assurance for production in over-supplied markets with limited infrastructure or to enable our production to reach higher priced out-of-basin markets. We have commitments to deliver approximately 350 Bcf of natural gas produced onshore US, primarily in the Marcellus Shale, to customers under long-term contracts ranging from one to 14 years.

Israel Natural Gas Sales and Purchase Agreements (GSPA) 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, 2014, a total of approximately 6.0 Tcf, gross (2.2 Tcf, net), of natural gas remained to be delivered under the contracts. As of December 31, 2014, we have recorded 2.4 Tcf, net, of proved natural gas reserves, including proved developed reserves of 1.9 Tcf, net, and PUD reserves of 443 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 2014 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 22% of 2014 total crude oil, natural gas and NGL sales, or 32% of 2014 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 10% of 2014 total crude oil, natural gas and NGL sales, or 15% of crude oil sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil, natural gas and NGL sales in 2014. 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 were volatile in 2014 and prices for crude oil and natural gas 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 and natural gas. 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 7. 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.

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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 exploration and development activities in the UK sector of the North Sea;
- the Petroleum Directorate which regulates our exploration activities offshore Sierra Leone; 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 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

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the future be designated as hazardous and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements. See Item 1A. Risk Factors.

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 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. 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.

On May 17, 2010, the BLM issued a revised oil and gas leasing policy for federal lands that requires, among other things, a more detailed environmental review prior to leasing crude oil and natural gas rights, increased public engagement in the development of master leasing and development plans prior to leasing any area where intensive new oil and gas development is anticipated, and a comprehensive parcel review process.

In 2009, the EPA launched a program that requires many suppliers of hydrocarbon fuels or industrial chemicals, manufacturers of vehicles and engines, and other facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year to report their annual GHG emissions. In November 2010, the EPA issued final regulations requiring such annual reporting of GHG emissions from qualifying facilities in the upstream oil and natural gas sector, including onshore production and offshore platforms (Subpart W). The first annual reports under Subpart W were due in 2012 for 2011 emissions. Substantially all of our onshore US properties are subject to the Subpart W reporting requirements. Information in such reports could form the basis of future GHG regulations.

On August 16, 2012, 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. These regulations require technologies and processes that, while reducing emissions, will enable companies to collect additional natural gas that can be sold. The EPA's final standards also address emissions from storage tanks and other equipment. The final rules establish a phase-in period that is intended to ensure that manufacturers have time to make and broadly distribute the required emissions reduction technology. Until January 2015, for example, owners and operators of natural gas wells must either flare their emissions or use emissions reduction technology called “green completions,” technologies that are already widely deployed at wells. In 2015, all newly fractured natural gas wells will be required to use green completions. The EPA's final rules are expected to have minimal impact on our business. The reduction of GHG emissions already was one of our priorities and we have been working to improve our methods to reduce GHGs through operational and business practices. For example, we use green completions on a number of our wells to comply with Colorado Oil and Gas Conservation Commission (COGCC) rules. Additionally 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 has announced that it intends to issue a proposed rule in the summer of 2015 to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. As another prong of the strategy, BLM is expected to propose standards in 2015 for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Obama Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

Also, the EPA has proposed to strengthen the National Ambient Air Quality Standard for ozone. Adoption of a stricter standard for ozone eventually would result in increased control requirements for sources of volatile organic compounds such as our operations.

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 COGCC to address oil and gas well drilling, production, commingling and spacing in Wattenberg (located in the DJ Basin). On August 9, 2011, the COGCC approved amendments to Rule 318A. The amendments, which became effective on October 1, 2011, remove 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 address areas such as infill drilling, water sampling and waste management plans.

In February 2013, the COGCC approved new setback rules for crude oil and natural gas wells and production facilities located in close proximity to occupied buildings. Previously, the COGCC 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 new 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 new 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 expanded outreach and communication efforts by an operator.

The COGCC also approved two new rules making Colorado the first state to require sampling of groundwater for hydrocarbons and other indicator compounds both before and after drilling. Those new 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 rule 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. On the air side, 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 would 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.

During 2014, moreover, we actively worked to avoid statewide ballot initiatives that could have resulted in other significant limitations on crude oil and natural gas development in Colorado. On August 4, 2014, an agreement was reached with proponents of adverse ballot initiatives whereby they agreed to withdraw them and support the creation of a Task Force on State and Local Regulation of Oil and Gas Operations (Task Force). By executive order, Colorado Governor Hickenlooper created the 21-member Task Force for the purpose of recommending policies and legislation by February 27, 2015. The Task Force is focused on how to reasonably and effectively balance land use issues in a way that minimizes conflicts while protecting communities and allowing reasonable access to private mineral rights.

A Noble Energy representative is a member of the Task Force.

Nevada In Nevada, state regulators recently promulgated rules to govern hydraulic fracturing and crude oil and natural gas development. We have actively participated in that process and do not believe it will have a material impact on our activities.

Pennsylvania On February 14, 2012, Governor Tom Corbett of Pennsylvania signed into law what is known as Act 13 of 2012 (Act 13). Act 13 represents the first comprehensive legislation regarding the development of the Marcellus Shale in Pennsylvania. Act 13, among other things, enacted stronger environmental standards and established impact fees, which in 2012 equaled $50,000 for each horizontal Marcellus Shale well. Act 13 also increased the notice distance of unconventional well permit applications from 1,000 feet to 3,000 feet, and extended the setback distance for unconventional wells from 200 feet to 500 feet. The statute also 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

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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 March 2012, seven municipalities filed suit against Act 13's statewide zoning provisions, claiming that Act 13 violated the state constitution. On July 26, 2012, the Pennsylvania Commonwealth Court declared the statewide zoning provisions in Act 13 unconstitutional, null, void and unenforceable. The Court also struck down the provision of the law that required the Pennsylvania Department of Environmental Protection to grant waivers to the setback requirements in Pennsylvania's Oil and Gas Act. This decision was appealed to the Pennsylvania Supreme Court, which upheld the lower court's decision. In response to another challenge, in 2014 the 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.

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.

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 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.

Israel's Natural Gas Policy In 2011, the Interministerial Committee was charged with the task of proposing a government policy for developing the natural gas economy. Objectives included providing a framework for substantial resource exports, designating a certain percentage of production from each field for domestic natural gas demand, and maintaining competition in the different sectors of the local economy.

In September 2012, the Committee issued its final recommendations which included, among others: a provision that permitted the export of natural gas as long as the quantity allowed for exports from all reservoirs does not exceed specified quantities, which amount may be reassessed; a provision that required regulatory approval for export, with export licenses eligible for periods up to 25 years; and a recommendation that steps should be taken to increase competition in the natural gas market.

On June 23, 2013, the Israeli government approved the main recommendations of the Committee with certain amendments, including an additional limitation on the exports allowed from the Tamar field (50% of uncontracted quantities).

On March 26, 2014, the Ministry of Finance issued a memorandum indicating its intent to amend the Petroleum Profits Law to regulate the method of taxing petroleum export transactions, and, in particular, exports of natural gas. We are currently evaluating the recommendation and proposed amendments and have submitted comments and suggestions to the Ministry.

General elections in Israel have been scheduled for March 17, 2015, and we anticipate a delay in achieving regulatory certainty until a new government is in place.

See also Update on Core Area – Israel, above.

Israel Antitrust Authority The Israeli Antitrust Commissioner (Commissioner) has been actively engaged to encourage competition in developing Israel's natural gas resources. Among other actions, the Commissioner has ruled that all domestic natural gas sales contracts are subject to review and approval of the Antitrust Authority and has intervened regarding the terms used in long-term contracts with certain natural gas customers.

The Commissioner also initiated a hearing process to evaluate a contention that allegedly the original acquisition agreement for the Leviathan acreage is a restrictive arrangement. The Commissioner publicly expressed concerns regarding ownership concentration in exploration blocks and development projects and its potential impacts on a competitive domestic natural gas market.

We have been engaged in discussions with the Antitrust Authority's review of these, and other matters, and in March 2014, we and our partners reached an agreement with the Antitrust Authority on various matters. The Consent Decree, which was subject to final approval by the Antitrust Tribunal, granted the rights, to us and our partners, to jointly market natural gas from the Leviathan field. Also as a result of the Consent Decree, we agreed to divest our Tanin and Karish natural gas discoveries. However, on December 23, 2014, we and our partners in the Leviathan field were advised by the Israel Antitrust Authority of its decision to not submit the Consent Decree to the Antitrust Tribunal for final approval.

This is a matter that we believed was resolved some time ago and we had received assurances from the Antitrust Authority that approval was forthcoming. We requested an oral hearing with the Antitrust Authority, which took place on January 27, 2015, and await final disposition.

Final resolution of this item, as well as other regulatory matters, is required before we proceed with additional exploration or development in Israel. If necessary, we expect to vigorously defend our rights relating to our assets.

See also Update on Core Area – Israel, above.

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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. The Dodd-Frank Act mandates that the Commodities Futures Trading Commission (CFTC) adopt rules and regulations implementing the derivatives market provisions of the Dodd-Frank Act, including requirements that certain transactions be cleared on exchanges and that collateral (commonly referred to as “margin”) be posted for uncleared swaps and other derivatives transactions. Although there is an exception from swap clearing and trade execution requirements for commercial end-users that meet certain conditions (commonly referred to as the “end-user exception”), certain market participants, including most if not all of our counterparties, will be required to clear many of their swap transactions with entities that do not satisfy the end-user exception and will have to transact many of their swaps on swap execution facilities or designated contract markets, rather than over-the-counter on a bilateral basis.

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. Although the Dodd-Frank Act’s margin requirements, and CFTC proposed rules, would have applied to end users, recent legislation has relieved end users of this requirement. In particular, 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 August 22, 2012, the SEC adopted Rule 13q-1 under the Exchange Act, which would have required 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. That rule, however, was vacated by the District Court for the District of Columbia on the grounds that (i) the SEC misread the statute to require public filing of the information and (ii) the SEC erred in denying an exemption where foreign law prohibits disclosure of payments. The SEC declined to appeal the court’s decision and, instead, is expected to promulgate a revised rule that is responsive to the court’s holdings. We expect that the new rule proposal will be subject to a process of public notice and comment, which generally takes several months to complete, and will not become effective until after the publication of a final revised rule.

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. 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.

The EPA is also currently studying the potential impacts of hydraulic fracturing on drinking water resources. Results are expected to be released in a draft for public and peer review in 2015.

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.

As drafted, the rules would require companies to:

- disclose chemicals they inject by using an online database, with an exception for chemicals deemed to be trade secrets;
- verify that wells are drilled properly so that toxic fluids do not contaminate groundwater; and
- submit plans for managing drilling wastewater in lined pits or storage tanks.

BLM’s final requirements may be different. Because oil and gas drilling and development activities, including hydraulic fracturing practices, are already regulated at the state level, compliance with federal hydraulic fracturing regulations may result in additional costs and reporting burdens. The final rules are expected to be published in 2015.

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, 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 the Colorado 2013 general election, the municipalities of Boulder, Broomfield, Fort Collins and Lafayette each passed similar ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries. To date, court challenges to several of these ordinances have been successful. 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

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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.

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.

In Nevada, where we are identifying additional exploration opportunities, state regulators recently promulgated rules to govern hydraulic fracturing and crude oil and natural gas development. We have actively participated in that process and do not believe it will have a material impact on our activities. New state regulations governing hydraulic fracturing practices have been adopted. Noble Energy actively participated in the public process which led to the creation of the statute and regulations.

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 Texas Railroad Commission (RRC) adopted the Hydraulic Fracturing Chemical Disclosure rule, which requires companies to disclose, on a public registry, chemical ingredients used to hydraulically fracture wells. 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 2009 we began acquiring our 370,000 fairly contiguous acreage position in northeast Nevada. It took over two years to assemble adequate acreage to warrant data collection. Once the acreage position had been established, we conducted extensive 3D seismic surveys and obtained other data, which our exploration staff analyzed and used to plan an initial drilling program. During 2013, we initiated an exploratory vertical well pilot program. Drilling locations were driven by analysis of the 3D seismic surveys. We must integrate data, such as core samples and well logs obtained from the drilling process, with our seismic and other data to determine if we have discovered hydrocarbons. In northeast Nevada, we are analyzing results from our exploratory wells drilled during 2014.

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 14. Segment Information.

Employees

Our total number of employees increased 8%, from 2,527 at December 31, 2013 to 2,735 at December 31, 2014, in support of our major development and exploration projects. The 2014 year-end employee count includes 285 foreign nationals working as employees in Israel, Cyprus, Equatorial Guinea, Cameroon, Nicaragua, and the UK. 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 Houston, Texas; Ardmore, Oklahoma; Denver, Colorado; Greeley, Colorado; Canonsburg, Pennsylvania; Washington, D. C.; and in Cameroon, Equatorial Guinea, Israel, Cyprus, Mexico, Nicaragua, Falkland Islands, China 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.

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 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.

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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, 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.

Crude oil, natural gas, and NGL prices are volatile and a reduction in these prices could adversely affect our results of operations, our liquidity, and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil, natural gas, and NGL production. Historically, the markets for crude oil, natural gas, and NGLs have been volatile and are likely to continue to be volatile in the future. High and low monthly daily average prices for crude oil and high and low contract expiration prices for natural gas during 2014 were as follows:

	Daily Average Settlement Price for Prompt Month Contracts	
	High	Low
Year Ended December 31, 2014		
NYMEX		
Crude Oil - WTI (Per Bbl) [1]	$105.15	$59.29
Natural Gas - HH (Per MMBtu)	5.56	3.73
Brent		
Crude Oil (Per Bbl)	111.76	62.91

[1] Prices for our US NGL production are determined at two primary market centers, Conway and Mt. Belvieu. For the year ended December 31, 2014, US average realized NGL prices tended to track the volatility of NYMEX WTI.

During fourth quarter 2014, a significant decline in crude oil prices occurred. As a result, we experienced decreases in crude oil revenues and recorded asset impairment charges due to commodity price declines. If crude oil prices continue to decline, further operating asset impairment or a goodwill impairment could occur, and our profitability will likely be negatively affected. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

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

- economic factors impacting global gross domestic product growth rates;
- global demand for crude oil, natural gas and NGLs;
- global factors impacting supply quantities of crude oil, natural gas and NGLs, in particular, US crude oil and NGL supply growth resulting from shale oil development;

- Organization of Petroleum-Exporting Countries (OPEC) spare capacity relative to global crude oil supply and crude oil pricing strategies;
- the extent to which US shale producers become swing producers, yielding additional non-OPEC crude oil supply;
- further application of horizontal drilling techniques which could increase production and significantly impact both domestic and global supplies of crude oil, natural gas, and NGLs;
- our ability to develop natural gas in shale or crude oil in tight formations relatively inexpensively which could increase the supply of natural gas or crude oil;

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- developments in the global LNG market, including potential exports from the US;
- actions taken by foreign hydrocarbon-producing nations;
- political conditions and events (including instability or armed conflict) in hydrocarbon-producing regions;
- the existence of government imposed price and/or product subsidies;
- 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 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.

Declines in commodity prices or inadequate transportation and storage of our product may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;
- curtailment or shut-in of our production due to lack of transportation or storage capacity;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- further reduction of our 2015 capital investment program, or significant reductions in future capital investment programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- limitations on our access to sources of capital, such as equity and debt; and
- declines in our stock price.

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

- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment;
- additional counterparty credit risk exposure on commodity hedges; and
- reduction in the carrying value of goodwill.

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. We have expanded our horizontal drilling programs in the DJ Basin and Marcellus Shale and are currently moving forward on the Gunflint, Big Bend and Dantzler development projects. In addition, we have invested significantly in the potential development of Leviathan Phase 1. Cyprus, Carla and Diega discoveries are being appraised and, as such, are not yet sanctioned. It will take several years before first production is achieved on some of these projects.

Offshore projects 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. Additionally, we are considering multiple future integrated development plans, which provide significant facilities and operating efficiencies, for our horizontal Niobrara and Marcellus Shale development projects.

This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. In addition, we depend on third-party technology and service providers and other supply chain participants for these complex projects. We may not be able to fully execute these projects due to:

- the current low commodity price environment;
- lack of government approval for projects, including Israeli government approval for Leviathan Phase 1 development;
- inability to attract and/or retain a sufficient quantity of personnel with the skills required to bring these complex projects to production on schedule and on budget;
- significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure which could adversely affect project development;
- civil disturbances, anti-development activities, legal challenges or other potential interruptions which could prevent access; and

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- drilling hazards or accidents or natural disasters.

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

See also Items 1 and 2. Business and Properties – Update on Core Area – Israel.

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

We have significant international operations, with approximately 40% of our 2014 total consolidated sales volumes coming from international areas. We are also conducting exploration activities in these and other international areas. Our operations may be adversely affected by political and economic developments, 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 as a result of the Deepwater Horizon Incident, a large oil spill occurring in the Gulf of Mexico in 2010, or other incidents that have occurred;
- laws and policies of the US and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- foreign exchange restrictions;
- 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.

Certain of these risks could be intensified by large crude oil or natural gas discoveries in areas where we are currently conducting offshore exploration activities, such as the Gulf of Mexico or Falkland Islands. Large discoveries, such as ours in the Levant Basin, may have impacts on global natural gas supplies.

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 Core Area – Israel.

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 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.

Currently, 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 is in the process of issuing guidance on Base Erosion and Profit Shifting (BEPS), an initiative which aims to standardize and modernize global tax policy. Adoption of BEPS by foreign jurisdictions in which we operate could result in changes to tax policies, including transfer pricing policies. To the extent such changes are retroactive, currently producing projects could become 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

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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 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 Core Area – Israel.
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 have increased significantly. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred.
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:

- volatility in global crude oil 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 resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;

- 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.

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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.

Concentration of our operations in a few core areas may increase our risk of production loss.

Our operations are concentrated in five core areas: the DJ Basin, the Marcellus Shale, and the deepwater Gulf of Mexico in the US; offshore West Africa; and the Eastern Mediterranean. These core areas provide almost all of our current production. In addition, production from the deepwater Gulf of Mexico, offshore West Africa, and the Eastern Mediterranean is from a relatively few number of deepwater wells. Although, individually, none of the core areas represented more than 35% of our 2014 total sales volumes, disruption of our business in one of these areas, such as from an accident, natural disaster, government intervention or other event, would have a significant impact on our production profile, cash flows and overall business plan.

We do not maintain business interruption (loss of production) insurance for all of our assets. Loss of production or limitations on our access to reserves in one of our core operating areas could have a significant negative impact on our cash flows and profitability.

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

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

- injuries and/or deaths of employees, supplier personnel or other individuals;
- pipeline ruptures and spills;
- fires, explosions, blowouts and well cratering;
- equipment malfunctions and/or mechanical failure on high-volume, high-impact wells;
- 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;
- surface spillage of, or contamination of groundwater by, fluids used in operations;
- security breaches, cyber attacks, piracy or terroristic acts;
- theft or vandalism of oilfield equipment and supplies, especially in areas of active onshore operations;
- hurricanes, cyclones, windstorms, or “superstorms” which could affect our operations in areas such as the Gulf Coast, 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;
- volcanoes which could affect our operations offshore Equatorial Guinea;
- flooding which could affect our operations in low-lying areas;
- harsh weather and rough seas offshore the Falkland Islands, which could limit certain exploration activities;
- other natural disasters; and
- pandemics and epidemics, such as the Ebola virus, which is ongoing in certain regions of West Africa and may adversely affect our business operations through travel or other restrictions.

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 in several of our core areas. In addition, we are conducting offshore exploration activities in certain international locations. In certain areas or at certain times, there may be limited availability of suitable drilling rigs, drilling equipment, support vessels, and qualified operating personnel. Deepwater drilling rigs are typically subject to long-term contracts. 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. As a result, a well control

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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 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 choose 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. 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 drilling of a development dry hole or 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.

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.

Leviathan Phase 1 development would likely utilize an FPSO and underwater pipelines. This development option would require a multi-billion dollar investment and a number of years to complete.

We are monitoring any additional developments in Israel's regulatory environment to assess the possible impact, positive or negative, of any resulting laws or regulations on our future development activities. Certain changes in Israel's fiscal, and/or regulatory regimes or energy policies occurring as a result of Antitrust Authority rulings or 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 or controls over natural gas pricing could have a negative impact on our business including reduction of future growth rates, profitability and cash flows.

These, and other, regulatory matters must be resolved before we continue to invest in development activities offshore Israel.

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 Cyprus Block 12 could reduce our future growth and have negative effects on our operating results.

See Items 1. and 2. Business and Properties – Update on Core Area – Israel.

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.

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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. The scope and enforcement of anti-corruption laws and regulations may vary. The UK Bribery Act of 2010, which became effective in 2011, 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.

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 could damage our reputation, be expensive to defend, and impair our ability to do business.

Derivatives regulation included in current or proposed financial legislation and rulemaking could impact our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In the US, the Dodd-Frank Act, which was passed by Congress and signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post collateral (commonly referred to as “margin”) for such transactions. The Act provides for an exception from these clearing and collateral requirements for commercial end-users, such as us, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use derivative instruments with respect to a portion of our expected crude oil and natural gas production in order to reduce the impact of commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our production and in support of our capital investment program. We may use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. As commodity prices increase or interest rates decrease, our derivative liability positions increase. None of our current derivative contracts require the posting of margin or similar cash collateral.

Some of the dealer counterparties to our derivative transactions could experience significant burdens from recent changes in derivatives regulation, If so, certain market participants may elect to curtail or cease their derivatives activities, which could increase the cost or limit the availability of derivative instruments and adversely affect our ability to manage business and financial risks.

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. 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. 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; 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 drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- 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;
- 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 one 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.

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 on the use of hydraulic fracturing. Because of elevated public sensitivity around the topic, federal and state governments are continually evaluating their regulatory programs and considering additional requirements on hydraulic fracturing practices. 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. At the national level, for example, federal agencies addressing hydraulic fracturing include the US Department of the Interior, which is currently working on its second draft of a federal regulation for hydraulic fracturing on federal and Native American lands. The draft rule has been estimated to have a potentially significant economic impact on the industry operating on federal or Native American lands. The final version of the rule is expected to be published in early 2015. Even at the local level, some municipalities have restricted or prohibited drilling activities, or are considering doing so.

Additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business, such as the DJ Basin or Marcellus Shale, 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.

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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 and/or foreign governments' 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;
- 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: northeast Nevada, offshore Cyprus, offshore the Falkland Islands, offshore Sierra Leone, and offshore Gabon. 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;
- exploration activities on federal lands in northeast Nevada subject us to additional regulatory requirements as compared with such activities conducted on private land;
- 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
- 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. 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

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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. The development of new environmental initiatives or regulations related to water acquisition or waste water disposal could also limit our ability to use techniques such as hydraulic fracturing. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may 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, 2014, we had $6.2 billion of debt, of which $68 million is due within 12 months. Our indebtedness represented 38% of our total book capitalization (sum of debt plus shareholders' equity) at December 31, 2014.

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 limit our ability to borrow additional funds, 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. A lowering of our credit rating may negatively affect the cost, terms, conditions and availability of future financing.

Increased banking regulation could result in reduced access to traditional sources of funding and limit our growth.

In response to the global economic crisis of 2008, banking regulation has increased. New regulation includes the Basel III rules issued by the Basel Committee on Banking Supervision and the Final Report of the UK's Independent Commission on Banking (also known as the Vickers Report). These, and other potential regulations being considered by governing bodies in the US and other countries, are expected to impact the amount of capital required to be held by banks and the nature of such capital. As a result, traditional lending practices could change, resulting in more restricted access to funds or reduced availability of funds at rates and terms we consider to be economic. Increased regulation could also negatively impact the project finance market, even for investment grade companies such as we are, and reduce our ability to obtain funding for the capital requirements of future major development projects.

Inability of us and/or our partners to obtain financing could result in delay or cancellation of future development projects, thus limiting our growth and future cash flows.

Slower global economic growth rates may materially adversely impact our operating results and financial position.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Market volatility and reduced 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 and international financial markets and credit rating agencies are pressing for budgetary reform and discipline. This need for fiscal discipline is balanced by calls for continuing government stimulus and social spending as a

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result of the impacts of the global economic crisis. As major countries implement government fiscal reform, such measures, if they are undertaken too rapidly, could further undermine economic recovery, reducing demand and slowing growth. Impacts of the crisis could spread to China and other emerging markets, which have fueled global economic development in recent years, slowing their growth rates, reducing demand, and resulting in further drag on the global economy.

Global economic growth drives demand for energy from all sources, including hydrocarbons. A lower future economic growth rate is likely to result in decreased demand growth for our crude oil, natural gas and NGL production. A decrease in demand, notwithstanding impacts from other factors, could potentially 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.

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 an active exploratory drilling program in 2015. 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;
- 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 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.

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

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.

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 may be unable to make attractive acquisitions, successfully integrate acquired businesses and/or assets, or adjust to the effects of divestitures, causing a disruption to our business.

One aspect of our business strategy calls for acquisitions of businesses and assets that complement or expand our current business. This may present greater risks for us than those faced by peer companies that do not consider acquisitions as a part of their business strategy. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive opportunities, we may not be able to complete the acquisition due to capital market constraints, even if such capital is available on commercially acceptable terms. If we acquire an additional business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own, or could assume unidentified or unforeseeable liabilities, resulting in a loss of value.

We maintain an ongoing portfolio management program which includes sales of non-core, non-strategic assets. These transactions can also result in changes in operations, systems, or management and other personnel.

Organizational modifications due to acquisitions, divestitures or other portfolio management actions, or other strategic changes can alter the risk and control environments, disrupt ongoing business, distract management and employees, increase expenses and adversely affect results of operations. The anticipated benefits of any acquisition, divestiture or other strategic change may not be realized.

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We may be unable to dispose of non-core, non-strategic assets on financially attractive terms, resulting in reduced cash proceeds and/or losses.

We maintain an ongoing portfolio management program according to which we may divest non-core, non-strategic assets. The program generated combined net proceeds of $2.4 billion during the last five years, including $321 million during 2014. Asset divestitures can generate organizational and operational efficiencies as well as cash for use in our capital investment program or to repay outstanding debt.

We strive to obtain the most attractive prices for our assets. However, various factors can materially affect our ability to dispose of assets on terms acceptable to us. Such factors include current commodity prices, laws and regulations impacting oil and gas operations in the areas where the assets are located, willingness of the purchaser to assume certain liabilities such as asset retirement obligations, our willingness to indemnify buyers for certain matters, and other factors. Inability to achieve a desired price for the assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities which must be settled in the future at amounts that are higher than we had expected.

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.

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 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.

Historically, we have funded our capital expenditures through a combination of cash flows from operations, our Credit Facility, debt 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 2015, 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 2015 capital investment program. As a result, we would have a reduced ability to replace our reserves, resulting in lower production over time. If in the future cash flows from operations are reduced and we are unable to access additional funding economically, our ownership interests or rights to participate in some properties might be reduced or forfeited as a result. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook 2015 – Capital Investment Program.

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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, which potentially includes an FPSO and/or major underwater pipeline, 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. Credit enhancements have been obtained from some parties in the way of parental guarantees, letters of credit or credit insurance; however, not all of our trade credit is protected through guarantees or credit support. 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 conduct our hedging activities with a diverse group of investment grade major banks and market participants, and we monitor and manage our level of financial exposure. 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. "Net settlement" refers to a process by which all transactions between counterparties are resolved into a single amount owed by one party to the other.

We had approximately $1.2 billion in cash and cash equivalents at December 31, 2014, a majority of which was invested in money market funds and short-term deposits with major financial institutions. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. However, we are unable to predict sudden changes in solvency of our financial institutions.

We monitor the creditworthiness of our trade creditors, joint venture partners, hedge counterparties and financial institutions on an ongoing basis. However, if one of them were to experience a sudden change 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 production. 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. In addition, hedging transactions may 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.

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 7. Derivative Instruments and Hedging Activities.

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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 and other unfortuitous 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.

As is customary with industry practices, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from unfavorable loss severity 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, at a level that balances cost of insurance with our assessment of risk and our ability to achieve a reasonable rate of return on our investments. Although we believe the coverages and amounts of insurance carried are adequate and consistent with industry practice, we do not have insurance protection against all the risks we face, because we chose 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 regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

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 the legislative and regulatory response to the Deepwater Horizon incident of 2010 and its 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 and state 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 and at times may force us to incur additional costs as those changes are implemented, or in instances of possible non-compliance, we may be subject to penalties. Additionally, the discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to substantial liabilities on our part to government agencies and third parties, and may require us to incur substantial costs of remediation.

Future legislation or regulation 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 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 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

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- 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 US energy policy could have a significant impact on our operations and profitability.

US energy policy and laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential rules and regulations that could impact the sources and uses of energy in the US. For example, new CAFE standards enacted in 2012 will result in a significant increase in the fuel economy of cars and light trucks and will reduce the future demand for crude oil for road transport use. On the other hand, GHG emissions regulations may increase the demand for natural gas as 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 US energy policy.

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 in which we concentrate, such as our core US operating areas, and in some international locations that typically have limited availability of equipment and personnel. Due to increasing levels of industry exploration and production that has recently occurred in US shale plays, the demand pressure for drilling rigs and oilfield services resulted in sector inflation.

Although crude oil prices fell significantly during fourth quarter 2014, certain costs may not have yet decreased in the same proportion. In addition, long-term drilling rig contracts may require us to pay rates higher than market if drilling costs decline significantly in the future. As a result, an increase in profits may be more dependent on cost reduction than in recent years.

Regulatory changes, such as those related to hydraulic fracturing, 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.

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Disclosure Regarding Forward-Looking Statements

This annual report on Form 10-K and the documents incorporated by reference in this report contain forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events.

These forward-looking statements include, among others, the following:

- our growth strategies;
- our 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

West Virginia Matter In March 2013, we received seven Notices of Violation (NOV) and two Administrative Orders (Orders) from the West Virginia Department of Environmental Protection Office of Oil and Gas (OOG) regarding the unintentional discharge of a mixture of freshwater and produced water that occurred on or about the evening of February 22, 2013 from one of our permitted water storage facilities in Marshall County, West Virginia. In July 2014, we reached a resolution with OOG regarding the NOVs and Orders. The resolution of these proceedings did not have a material adverse effect on our financial position, results of operations or cash flows.

Colorado Air Matter In August 2013, we received an information request from the EPA under Section 114 of the Clean Air Act regarding several tank batteries used in our DJ Basin operations. The information request relates to our compliance with certain regulatory requirements at those locations, including air emissions of volatile organic compounds in a marginal ozone non-attainment area. We responded to the EPA’s information requests between November 2013 and April 2014 and are in settlement discussions with the EPA and the State of Colorado regarding potential noncompliance with the Clean Air Act, Colorado's State Implementation Plan, Colorado's Air Pollution Prevention and Control Act and its implementation regulations. To date, no federal or state enforcement action has been commenced in connection with this matter. We anticipate that resolution of this matter will result in civil penalties of an undetermined amount and require us to undertake corrective actions which may increase our development and/or operating costs. Given the uncertainty in matters such as these, we are unable to predict the ultimate outcome of this matter at this time. However, we do not believe that any penalties or remediation expenditures that may result from this matter will have a material adverse effect on our financial position, results of operations or cash flows.

See also Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

Item 4. Mine Safety Disclosures

Not Applicable.

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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 (1)	Low (1)	Dividends Per Share(1)
2013			
First Quarter	$58.23	$51.62	$0.13
Second Quarter	61.25	53.25	0.14
Third Quarter	67.77	59.88	0.14
Fourth Quarter	77.13	64.80	0.14
2014			
First Quarter	$76.34	$66.49	$0.14
Second Quarter	79.23	69.34	0.18
Third Quarter	71.14	61.19	0.18
Fourth Quarter	66.79	43.00	0.18

(1) Amounts adjusted for the 2-for-1 stock split which occurred during second quarter 2013.

On January 27, 2015, the Board of Directors declared a quarterly cash dividend of $0.18 per common share, which will be paid February 23, 2015 to shareholders of record on February 9, 2015.

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, 2015, the number of holders of record of our common stock was 617.

Stock Repurchases The following table summarizes repurchases of our common stock occurring in fourth quarter 2014.

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)
10/1/2014 - 10/31/14	711	$57.07	—	—
11/1/2014 - 11/30/14	990	56.72	—	—
12/1/2014 - 12/31/14	93	47.33	—	—
Total	1,794	$56.37	—	—

(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.

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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, 2014:

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	13,008,322	$43.98	15,224,147
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	13,008,322	$43.98	15,224,147

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2009 to December 31, 2014. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index, an old peer group of companies and a new peer group of companies. The cumulative total return of the common stock of our old and new peer groups of companies includes the cumulative total return of our common stock.

The companies in the old peer group consisted 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.
Newfield Exploration Company
Noble Energy, Inc.
Pioneer Natural Resources Company
Range Resources Corp.
Southwestern Energy Company

On January 27, 2014, the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) made changes to our compensation peer group to remove Newfield Exploration Company from the old peer group listed above. After the change in companies, the 2014 compensation peer group consisted 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

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The comparison assumes $100 was invested on December 31, 2009 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,	2009	2010	2011	2012	2013	2014
Noble Energy, Inc.	$100.00	$122.04	$135.02	$146.94	$198.47	$139.68
S&P 500	100.00	115.06	117.49	136.30	180.44	205.14
Old Peer Group	100.00	114.52	108.46	109.28	143.35	123.70
New Peer Group	100.00	113.60	109.24	110.71	145.82	125.49

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Item 6. Selected Financial Data

	Year Ended December 31,				
(millions, except as noted)	2014	2013	2012	2011	2010
Revenues and Income					
Total Revenues	$5,101	$5,015	$4,223	$3,404	$2,713
Income from Continuing Operations	1,214	907	965	412	631
Net Income	1,214	978	1,027	453	725
Per Share Data [1]					
Earnings Per Share - Basic					
Income from Continuing Operations	$3.36	$2.53	$2.71	$1.17	$1.80
Net Income	3.36	2.72	2.89	1.28	2.07
Earnings Per Share - Diluted					
Income from Continuing Operations	3.27	2.50	2.68	1.15	1.78
Net Income	3.27	2.69	2.86	1.27	2.05
Cash Dividends Per Share	0.68	0.55	0.45	0.40	0.36
Year-End Stock Price Per Share	47.43	68.11	50.87	47.20	43.04
Weighted Average Shares Outstanding					
Basic	361	359	356	353	350
Diluted	367	363	359	357	354
Cash Flows					
Net Cash Provided by Operating Activities	$3,506	$2,937	$2,933	$2,170	$1,946
Additions to Property, Plant and Equipment	4,871	3,947	3,650	2,594	1,885
Acquisitions	—	—	—	527	458
Proceeds from Divestitures	321	327	1,160	77	564
Financial Position					
Cash and Cash Equivalents	$1,183	$1,117	$1,387	$1,455	$1,081
Property, Plant, and Equipment, Net	18,143	15,725	13,551	12,782	10,264
Goodwill	620	627	635	696	696
Total Assets	22,553	19,642	17,554	16,444	13,282
Long-term Obligations					
Long-Term Debt	6,103	4,566	3,736	4,100	2,272
Deferred Income Taxes	2,516	2,441	2,218	2,059	2,110
Asset Retirement Obligations	670	547	333	344	208
Other	417	562	477	408	422
Shareholders' Equity	10,325	9,184	8,258	7,265	6,848
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	103	99	86	56	54
Average Realized Price ($/Bbl) [2]	$91.58	$100.29	$101.52	$99.17	$75.76
Consolidated Natural Gas Sales (MMcf/d)	992	901	774	806	781
Average Realized Price ($/Mcf) [2]	$3.38	$2.97	$2.19	$3.00	$2.98
Consolidated NGL Sales (MBbl/d)	23	16	16	15	14
Average Realized Price ($/Bbl)	$32.04	$35.53	$35.36	$48.35	$41.21
Proved Reserves					
Crude Oil and Condensate Reserves (MMBbls)	304	322	268	277	284
Natural Gas Reserves (Bcf)	5,833	5,828	4,964	5,043	4,361
NGL Reserves (MMBbls)	128	113	89	92	81
Total Reserves (MMBoe)	1,404	1,406	1,184	1,209	1,092
Number of Employees	2,735	2,527	2,190	1,876	1,772

(1) Amounts adjusted for the 2-for-1 stock split which occurred during second quarter 2013.
(2) Prices for 2010 include effects of crude oil and natural gas cash flow hedging activities.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. 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 worldwide 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, diversified portfolio of assets with investment flexibility between onshore unconventional developments and offshore organic exploration leading to major development projects; US and international projects; and production mix among crude oil, natural gas, and NGLs. We focus our efforts in five core operating areas: 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 superior returns. We also seek to enter potential new core areas, and we are currently conducting exploration activities in domestic and international locations.

Commodity Price Changes   The upstream oil and gas business is cyclical. During fourth quarter 2014, a significant decline in crude oil prices occurred resulting in lower revenues and reduced margins. NYMEX WTI crude oil prices fell approximately 50% between June and December, with a similar Brent crude oil price decline, due to falling demand, as well as world-wide oversupply exacerbated by OPEC's November decision to hold production steady. As a result, our total consolidated average realized crude oil prices for fourth quarter 2014 decreased almost 30% as compared with fourth quarter 2013. During early 2015, crude oil prices have continued to be weak.

We are unable to predict the extent to which crude oil prices may recover during 2015. Prices are likely to remain volatile and could decline further. In addition, we could be entering a period of sustained, lower worldwide crude oil prices.

We plan for these cyclical downturns in our business and feel we are well positioned to withstand current and future commodity price volatility:

- we have a high-quality, diversified portfolio of assets, a majority of which are held by production, which provide investment flexibility;
- we have positive operating cash flow (revenues less cash operating expenses), prior to capital expenditures, in each of our core areas;
- we have designed a substantially-reduced capital investment program which will allow us to respond to conditions that occur in 2015;
- we are well hedged, with approximately 60% of global crude oil and 50% of domestic natural gas production hedged for 2015, with additional quantities hedged into 2016;
- we have a strong balance sheet; and
- we have robust liquidity.

See Operating Outlook – 2015 Outlook below.

2014 Results Our recent growth was driven by our five core areas which we expect to provide for future long-term growth. In pursuit of our strategy, we progressed major development projects onshore US, in the deepwater Gulf of Mexico and offshore Israel, and continued exploration activities.

The growth of our DJ Basin and Marcellus Shale development programs resulted in total daily average sales volumes from continuing operations of 298 MBoe/d for 2014, an increase of 9% over 2013. In the DJ Basin, driven by expansion of horizontal drilling activity, we increased total 2014 daily production by 6%, as compared with 2013. Production from DJ Basin horizontal wells increased 28% year over year, while production from vertical wells declined 25% year over year.

In the Marcellus Shale, due to increased drilling activity, total 2014 daily production doubled as compared with 2013. We and our partner brought 129 new wells online.

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Our equity method investee, CONE Gathering, contributed a significant majority of its existing assets to a newly-formed master limited partnership, CONE Midstream. We own a 32.1% interest in CONE Midstream, which constructs, owns and operates natural gas midstream assets in support of our Marcellus Shale joint venture activities.
The deepwater Gulf of Mexico program moved forward with continued progress at the Gunflint, Big Bend and Dantzler developments and successful well results at the Dantzler-2 appraisal well and the Katmai exploratory well. We also drilled the Bright and Madison exploratory wells, which did not encounter commercial quantities of hydrocarbons.
Our international assets continue to contribute substantially with world-class reliability from major projects in the Eastern Mediterranean and West Africa, including Tamar (offshore Israel), Aseng (offshore West Africa), and Alen (offshore West Africa). Each of these projects is a technical and commercial milestone that significantly adds to our production profile. We have also been engaged in marketing activities for our Eastern Mediterranean natural gas discoveries, for both domestic and export sale. See Update on Israel Antitrust Matters, below.

2014 Financial Results Included:

- net income of $1.2 billion (all from continuing operations), as compared with $978 million (including $907 million from continuing operations) for 2013;
- gain on divestitures of $73 million, as compared with $36 million for 2013;
- dry hole expense of $226 million, as compared with $149 million for 2013;
- asset impairment charges of $500 million, as compared with $86 million for 2013;
- gain on commodity derivative instruments of $976 million (including $947 million non-cash portion), as compared with $133 million loss on commodity derivative instruments (including $131 million non-cash portion) for 2013;
- diluted earnings per share of $3.27, as compared with $2.69 for 2013;
- cash flows provided by operating activities of $3.5 billion, as compared with $2.9 billion in 2013; and
- capital spending of $5.0 billion, as compared with $4.4 billion in 2013.

Significant Events Impacting Liquidity Included:

- proceeds of $321 million from sales of non-core properties;
- cash distributions of $204 million from CONE Gathering subsequent to the formation of a master limited partnership for Marcellus Shale midstream assets and completion of the initial public offering; and
- issuance of $1.5 billion unsecured notes at Company-record low coupon levels.

Year-end Financial Metrics Included:

- ending cash and cash equivalents balance of approximately $1.2 billion at December 31, 2014, as compared with $1.1 billion at December 31, 2013;
- total liquidity of $5.2 billion at December 31, 2014 (consisting of year-end cash balance plus funds available under our Credit Facility) as compared with $5.1 billion at December 31, 2013; and
- year-end ratio of debt-to-book capital of 38%, as compared with 35% at December 31, 2013.

Update on Israel Antitrust Matters In March 2014, we and our partners reached an agreement with the Israeli Antitrust Authority on various matters. On December 23, 2014, the Israel Antitrust Authority advised us of its decision to not submit the agreement to the Antitrust Tribunal for final approval. We requested an oral hearing with the Antitrust Authority, which took place on January 27, 2015, and await final disposition. See Items 1. and 2. Business and Properties – Update on Core Area – Israel.

Asset Impairment Charges We recorded property impairment charges of $500 million for the year, including $336 million for fourth quarter 2014. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Acquisitions During second quarter 2014, we acquired working interests in 17 deepwater exploration leases in the Gulf of Mexico Atwater Valley protraction area. We acquired a 50% working interest in 13 leases and an average 26% working interest in four leases.

Divestitures Sales of non-core properties, including onshore US and China, generated proceeds of approximately $321 million during 2014, including $135 million related to the sale of onshore US assets and $186 million related to the sale of our China assets. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

Sales Volumes The execution of our business strategy, including accelerated activity in onshore US unconventional projects, delivered production growth during 2014. On a BOE basis, total sales volumes were 9% higher in 2014 as compared with 2013, and our mix of sales volumes in 2014 was 43% global crude oil and NGLs, 27% international natural gas, and 30% US natural gas. See Results of Operations – Revenues, below.

Commodity Hedging Activities To enhance the predictability of our cash flows and support our capital investment program, we hedged portions of our expected global crude oil and domestic natural gas production. In the current crude oil price environment, our hedges for 2015 production will contribute to our cash flows from operations, offsetting a portion of declines in crude oil revenues caused by lower prices. For example, during fourth quarter 2014, net cash received in settlement of commodity derivative instruments totaled almost $124 million, and our commodity derivative receivables totaled $890 million at December 31, 2014.

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 7. Derivative Instruments and Hedging Activities.

OPERATING OUTLOOK

2015 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 low 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. Prices have fallen to lows not experienced in almost six years and the lowest levels since the 2008 financial crisis. Thus far in 2015, there has been little to no recovery of prices and NYMEX crude oil futures continue to be weak.

The outlook for crude oil prices during the remainder of 2015 depends primarily on supply and demand dynamics and global security concerns in crude oil-producing nations. Production levels will be a key determinant for 2015. If, during 2015, OPEC maintains its position against cutting production, we expect prices to remain at or near current levels. 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 2015 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 balance. If prices remain at lower levels, we expect non-OPEC producers will reduce investment which will, over time, reduce production helping to balance supply and demand in the crude oil market.

Natural Gas The domestic natural gas market remains weak with prices recently falling to two-year lows. Causes include continued growth in domestic natural gas production, particularly from shale plays as well as de-bottlenecking of natural gas processing and transportation facilities in prolific production areas.

Although the pace of drilling appears to have 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 2015. At a minimum, we expect US natural gas prices to be range-bound. In addition, domestic production growth could continue through 2015 and 2016 as we see the impacts of increases in drilling efficiency and a backlog of drilled but uncompleted wells come online with completion of new pipeline infrastructure, especially in the northeast.

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 2015 capital investment program that will be responsive to conditions that will develop in 2015. This program, coupled with our commodity hedging programs, will support continued investment in a volatile commodity price environment. See 2015 Capital Investment Program, below.

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2015 Production Our expected crude oil, natural gas and NGL production for 2015 may be impacted by several factors including:

- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- the level of horizontal drilling activity in the DJ Basin and the Marcellus Shale;
- decline in DJ Basin legacy vertical well production and capacity constraints of midstream facilities serving those wells;
- timing of start-up of the Big Bend project (deepwater Gulf of Mexico);
- 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;
- 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;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico, or winter storms and flooding in the DJ Basin and/or Marcellus Shale;
- 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.

2015 Capital Investment Program Given the current commodity price environment with low prices and an industry cost structure that has yet to fully reset to lower revenue levels, we have designed a substantially-reduced capital investment program that is appropriate for the environment and will be responsive to conditions that develop during 2015. Our preliminary capital program for 2015 will accommodate an investment level of approximately $2.9 billion which represents an approximate 40% reduction from 2014. The program allocates more than 60% of total investment to core onshore US assets and 35% for global offshore development activities including the deepwater Gulf of Mexico, and approximately 5% for global offshore exploration.

Specifically, the 2015 investment program allocates approximately $1.8 billion to onshore US development split between DJ Basin and Marcellus Shale drilling programs and continued infrastructure investments. Approximately $600 million will be invested in the continued development of our sanctioned Gulf of Mexico projects. Additional amounts have been allocated to the Alba and Tamar compression projects.

The 2015 capital investment program is anticipated to exceed operating cash flows during the first half of 2015 and may be funded 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. We are targeting a cash neutral position, whereby the capital investment program is equal to operating cash flows, by the second half of 2015. See Liquidity and Capital Resources – Financing Activities.

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;
- 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 offshore Cameroon and the Falkland Islands;
- 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 also See Items 1. and 2. Business and Properties – Update on Core Area – Israel, and Liquidity and Capital Resources – Contractual Obligations – Marcellus Joint Development Agreement and Exploration Commitments.

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Exploration Program We continually evaluate our exploration inventory to provide additional growth opportunities and potential new core areas. In addition, each of our existing core areas has remaining exploration upside. We continue to leverage existing activities to improve our exploratory programs in these core areas.

In recent years, we have devoted 10% or more of our capital investment program to exploration and associated appraisal activities. However, due to the current low commodity price environment, our 2015 exploration program has been reduced. At this time, we expect that approximately 5% of our 2015 capital investment program will be dedicated to global offshore exploration activities, including drilling the Cheetah exploration well, offshore Cameroon, and frontier exploration activities in the Falkland Islands. 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 2015. 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 Asset Impairments, Dry Hole or Lease Abandonment Expense

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 expect to conduct exploration activities offshore Cameroon and the Falkland Islands in 2015. If we conclude that a prospect is not economically viable, costs incurred would be recorded as dry hole expense. Capitalized costs related to previous exploration activities totaled $1.3 billion at December 31, 2014. See Item 8. Financial Statements and Supplementary Data – Note 5. Capitalized Exploratory Well Costs.

Additionally, 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.

For example, we have worked to mature one particular deepwater Gulf of Mexico lease, which was acquired under regulations in effect prior to the Deepwater Gulf of Mexico Moratorium, and identified a potential subsalt hydrocarbon-bearing formation below 25,000 feet. The lease passed its original expiration date of July 31, 2014; however, it has been classified as inactive pending BSEE's decision on our timely application for a suspension of operations (SOO). Based on recent discussion with BSEE, we expect that the SOO application will be approved. According to proposed SOO terms, we must, by October 31, 2015, commit to drilling an exploratory well and commence drilling of the well by October 31, 2016. If BSEE does not approve our SOO application, or if we are unable to comply with approved SOO terms, the lease will expire and associated costs will be written off to exploration expense. The lease had a net book value of $42 million at December 31, 2014.

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

Producing Properties Commodity prices remain volatile and crude oil prices have continued to be weak in first quarter 2015. 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 alone could result in additional property impairment charges in first quarter 2015. Further decline in commodity prices could also result in an impairment of goodwill.

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

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availability of rigs and services. It may be difficult to estimate costs as rigs and services become more expensive in periods of higher demand. Therefore, our ARO estimates may change, sometimes significantly, and could result in asset impairment charges.

Israel Certain assets offshore Israel were classified as held for sale at December 31, 2014. No impairments are indicated at this time. However, failure to achieve acceptable sale terms or delays in closing sales of these properties could result in impairment and/or loss on sale.

In addition, we are monitoring developments in the Israeli regulatory environment to assess the possible impact, positive or negative, of any resulting laws or regulations on our future development activities in Israel. Certain changes in Israel's fiscal and/or regulatory regimes or energy policies occurring as a result of the Antitrust Authority rulings or government policy on natural gas development and/or exports could delay or reduce the profitability of our Tamar and/or Leviathan development projects, and/or render future exploration and development projects uneconomic, resulting in impairment charges. See Items 1. and 2. Business and Properties – Update on Core Area – Israel.

Divestments We are currently marketing certain non-core onshore US 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. In addition, we would allocate a portion of goodwill to any non-core onshore US property held for sale that constitutes a business, which could potentially decrease any gain or increase any loss recorded on the sale.

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

Climate Change The matter of climate change has become the subject of a significant public policy debate. While climate change remains a complex issue, some scientific research suggests that an increase in GHGs may pose a risk to the environment.

The crude oil and natural gas exploration and production industry is a source of certain GHGs, namely carbon dioxide and methane, and future restrictions on the combustion of hydrocarbons or the venting of natural gas could have a significant impact on our future operations. We are actively monitoring the following climate change related issues:

Impact of Legislation and Regulation The commercial risk associated with the exploration and production of hydrocarbons lies in the uncertainty of government-imposed climate change legislation, including cap and trade schemes, carbon taxes, and regulations 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 change 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 to the United Nations Framework Convention on Climate Change (Protocol) 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. The US did not ratify the Protocol. Parties have agreed to a second commitment period of the Kyoto Protocol which will last until December 31, 2020.

International negotiations over a new climate change accord are continuing. While no new accord has been adopted that would affect our operating locations, the current state of development of many initiatives makes it difficult to assess the timing or effect of any pending discussions of future accords or 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 response to potential climate change. 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 55% of our 2014 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.

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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. 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 years ended December 31, 2012 and 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,		
	2014	2013	2012
(millions, except per share)			
Total Revenues	$5,101	$5,015	$4,223
Total Operating Expenses	4,183	3,359	2,811
Operating Income	918	1,656	1,412
Total Other (Income) Expense	(792)	312	56
Income from Continuing Operations Before Income Taxes	1,710	1,344	1,356
Income from Continuing Operations	1,214	907	965
Discontinued Operations, Net of Tax	—	71	62
Net Income	1,214	978	1,027
Earnings from Continuing Operations Per Share			
Basic	3.36	2.53	2.71
Diluted	3.27	2.50	2.68

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

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Revenues

Oil, Gas and NGL Sales We generally sell crude oil, natural gas, and NGLs under two types of agreements, which are 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 each case, we record 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 the factors contributing to the changes in revenues from sales of crude oil, natural gas and NGLs is as follow:

	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
2012 Sales Revenues	$3,205	$620	$212	$4,037
Changes due to				
Increase in Sales Volumes	458	100	2	560
Increase (Decrease) in Sales Prices	(45)	256	1	212
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 in revenue are discussed below.

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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, 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
Year Ended December 31, 2012							
United States	49	438	16	139	$94.69	$2.61	$35.36
Equatorial Guinea [2]	33	235	—	72	110.14	0.27	—
Israel	—	101	—	17	—	4.85	—
China	4	—	—	4	114.54	—	—
Total Consolidated Operations	86	774	16	232	101.52	2.19	35.36
Equity Investees [3]	2	—	5	7	104.56	—	69.14
Total Continuing Operations	88	774	21	239	$101.58	$2.19	$44.15

(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 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.

(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 $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 the North Sea assets during 2013;

partially offset by:

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

Revenues from crude oil and condensate sales increased by $413 million, or 13%, in 2013 as compared with 2012 due to the following:

- higher sales volumes of 14 MBoe/d in the DJ Basin attributable to the acceleration of our horizontal drilling program;
- the addition of sales volumes from Alen, offshore Equatorial Guinea, which began producing in late second quarter 2013; and
- higher production at Galapagos due to continued strong performance and a full year online;

partially offset by:

- reduction in sales volumes due to the sales of non-core, onshore US properties during 2013;
- a 1% decrease in total consolidated average realized prices primarily due to increased supply;
- a volume reduction in West Africa due to natural field decline at Aseng; and
- natural field decline in non-core onshore US and deepwater Gulf of Mexico areas.

Natural Gas Sales 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.

Revenues from natural gas sales increased by $356 million, or 57%, in 2013 as compared with 2012 due to the following:

- increases in total consolidated average realized prices primarily due to increased demand from expectations of cooler weather and higher-than-expected inventory withdrawals;
- higher sales volumes in Israel from Tamar, which began production at the end of first quarter 2013 and contributed 153 MMcf/d during 2013; and
- higher sales volumes in the DJ Basin (15 MMcf/d) and Marcellus Shale (49 MMcf/d) in 2013 primarily attributable to our horizontal drilling programs;

partially offset by:

- lower sales volumes due to our non-core onshore US divestiture program; and
- lower sales volumes due to natural field decline from Mari-B, Noa and Pinnacles, offshore Israel, which contributed a combined 56 MMcf/d during 2013, compared with 101 MMcf/d during 2012.

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

- higher sales volumes of 3 MBoe/d in the DJ Basin, due to increased horizontal drilling activity; and
- higher sales volumes of 4 MBoe/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.

NGL sales revenues increased $3 million, or 1%, during 2013 as compared with 2012 as a result of slightly higher realized prices and a slight increase in sales volumes.

Income from Equity Method Investees We have interests in various equity method investees that own and 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.

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

	Year Ended December 31,		
	2014	2013	2012
Net Income (in millions)			
AMPCO and Affiliates	$62	$85	$64
Alba Plant	99	121	122
CONE Gathering and CONE Midstream	9	—	—
Dividends (in millions)			
AMPCO and Affiliates	61	82	70
Alba Plant	117	122	130
CONE Gathering and CONE Midstream[1]	204	—	—
Sales Volumes			
Methanol (MMgal)	130	155	156
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	6	5
Average Realized Prices			
Methanol (per gallon)	$1.26	$1.27	$1.07
Condensate (per Bbl)	96.53	105.37	104.56
LPG (per Bbl)	62.89	68.12	69.14

[1] $204 million dividends were distributed from CONE Gathering following the Midstream IPO.

AMPCO and Affiliates 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.

Net income from AMPCO and affiliates increased in 2013 as compared with 2012 primarily due to higher sales revenue from a 19% increase in average realized sales price of methanol.

Alba Plant Net income from Alba Plant in 2014 decreased as compared to 2013 and 2012, primarily due to an 8% decrease in the average realized sales price of LPG while sales volumes remained flat.

CONE Gathering 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)	2014	Inc (Dec) from Prior Year	2013	Inc (Dec) from Prior Year	2012
Production Expense	$958	13 %	$850	26 %	$673
Exploration Expense	498	20 %	415	1 %	409
Depreciation, Depletion and Amortization	1,759	12 %	1,568	14 %	1,370
General and Administrative	503	16 %	433	13 %	384
Gain on Divestitures	(73)	103 %	(36)	(77)%	(154)
Asset Impairments	500	481 %	86	(17)%	104
Other Operating (Income) Expense, Net	38	(12)%	43	72 %	25
Total	$4,183	25 %	$3,359	19 %	2,811

Changes in operating costs and expenses are discussed below.

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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, 2014						
Lease Operating Expense (3)	$5.68	$604	$354	$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	$9.01	$958	$688	$147	$54	$69
Total Production Expense per BOE		$9.01	$10.72	$5.44	$3.84	N/M
Year Ended December 31, 2013						
Lease Operating Expense (3)	$5.46	$530	$343	$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	$850	$626	$106	$48	$70
Total Production Expense per BOE		$8.76	$11.21	$3.97	$3.75	N/M
Year Ended December 31, 2012						
Lease Operating Expense (3)	$5.09	$431	$287	$89	$20	$35
Production and Ad Valorem Taxes	1.79	151	113	—	—	38
Transportation and Gathering Expense	1.06	91	87	—	—	4
Total Production Expense	$7.94	$673	$487	$89	$20	$77
Total Production Expense per BOE		$7.94	$9.60	$3.39	$3.23	N/M

N/M Amount is not meaningful. See (2) below.

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

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

(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 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.

Lease operating expense increased in 2013 as compared with 2012 due to the following:

- increases of $46 million in the DJ Basin and $4 million in the Marcellus Shale due to new wells coming on line and increased production;

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- an increase of $58 million in the deepwater Gulf of Mexico due to a full year of production at Galapagos, mechanical repairs at Swordfish, and other repair and maintenance expense;
- operating expenses of $24 million related to the Tamar field, offshore Israel, which began producing at the end of first quarter 2013; and
- operating expenses of $18 million related to the Alen field, offshore Equatorial Guinea, which began producing at the end of second quarter 2013;

partially offset by:

- a reduction of $52 million related to the sale of non-core onshore US properties in 2012 and 2013.

See also Discontinued Operations, below.

Production and Ad Valorem Tax Expense Production and ad valorem taxes 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.

Production and ad valorem tax expense increased in 2013 as compared with 2012. An increase of approximately $52 million due to higher production volumes and higher average prices in the DJ Basin in 2013 was offset by a $10 million decrease primarily due to the sale of non-core, onshore US properties in 2012 and 2013.

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

Transportation expense increased in 2013 as compared with 2012 related to increases of $25 million in the DJ Basin and $14 million in the Marcellus Shale due to increased production from ongoing development activities.

Unit Rate Per BOE 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.

The unit rate of total production expense per BOE increased for 2013 as compared with 2012 primarily due to a change in the mix of production, including higher DJ Basin volumes, which has higher cost to operate than our Equatorial Guinea and Israel production.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	Other Int'l, Corporate (3)
Year Ended December 31, 2014					
Dry Hole Cost	$226	$147	$—	$ —	$79
Seismic	64	24	16	4	20
Staff Expense	154	43	10	13	88
Other	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
Staff Expense	128	33	9	6	80
Other	41	40	—	—	1
Total Exploration Expense	$415	$124	$20	$ 24	$247
Year Ended December 31, 2012					
Dry Hole Cost	$155	$121	$34	$ —	$—
Seismic	81	59	4	—	18

Staff Expense	148	22	49	5	72
Other	25	23	1	—	1
Total Exploration Expense	$409	$225	$88	$ 5	$91

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone, Gabon, and Senegal/Guinea-Bissau, which we exited in 2012.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes various international new ventures such as offshore Nicaragua, which we are currently exiting, and offshore Falkland Islands.

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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.

Oil and gas exploration expense increased in 2013 as compared with 2012. Expense for 2013 includes the following:

- Other Int'l dry hole cost related to the Paraiso exploratory well (offshore Nicaragua), which did not find commercial quantities of hydrocarbons;
- seismic expense related to the Gulf of Mexico lease sale and exploration programs offshore Cyprus and offshore Falkland Islands; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense included stock-based compensation expense of $17 million in 2014, $15 million in 2013, and $12 million in 2012.

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

	Year Ended December 31,		
(millions, except unit rate)	2014	2013	2012
United States	$1,318	$1,117	$929
Equatorial Guinea	299	261	255
Israel	63	97	111
Other International, and Corporate	79	93	75
Total DD&A Expense (1)	$1,759	$1,568	$1,370
Unit Rate per BOE (2)	$16.55	$16.18	$16.16

(1) DD&A expense includes accretion of discount on asset retirement obligations of $36 million in 2014, $26 million in 2013, and $22 million in 2012.

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

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 from 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.

Total DD&A expense increased for 2013 as compared with 2012 due to the following:

- higher sales volumes due to increased development activity in the DJ Basin and Marcellus Shale accounted for increases of $218 million and $34 million, respectively;
- higher production at Galapagos and a new well at Ticonderoga, deepwater Gulf of Mexico, resulted in additional DD&A expense of approximately $48 million;

- the start up of Alen, offshore Equatorial Guinea, resulted in additional DD&A expense of $44 million; and
- the start up of Tamar, offshore Israel, resulted in additional DD&A expense of $40 million;

partially offset by:

- a decrease of approximately $53 million onshore US, primarily due to the impact of sales of non-core properties during 2012 and 2013;

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- a decrease of $52 million in the deepwater Gulf of Mexico due to maintenance and repair downtime and declining production at older fields;
- a decrease of $40 million at the Aseng field, offshore Equatorial Guinea, due to natural field decline and timing of liftings; and
- a decrease of $54 million at the Mari-B/Noa/Pinnacles fields, offshore Israel, due to natural field decline and decreased book value from previous impairments.

Changes in the unit rate per BOE for 2013 as compared with 2012 were due to change in the mix of production, including higher production in the DJ Basin and Marcellus Shale, which has a higher DD&A rate than our Equatorial Guinea and Israel production.

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

	Year Ended December 31,		
	2014	2013	2012
G&A Expense (millions)	$503	$433	$384
Unit Rate per BOE [(1)]	$4.73	$4.47	$4.53

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

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 increased for 2013 as compared with 2012 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

G&A expense is impacted by the number of stock-based awards, the market price of our common stock and price volatility, all of which result in a higher fair value of stock-based awards as calculated using the Black-Scholes-Merton option pricing model. G&A included stock-based compensation expense of $63 million in 2014, $58 million in 2013 and $48 million in 2012. See Item 8. Financial Statements and Supplementary Data – Note 11. Stock-Based and Other Compensation Plans.

Gain on Divestitures Gain on divestitures was as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Gain on Divestitures	$(73)	$(36)	$(154)

Gain on divestitures for 2014 relates to the sale of non-core onshore US properties and our China assets. Gain on divestitures for 2013 and 2012 is related to the sale of non-core onshore US assets. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

Asset Impairments Asset impairment expense was as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Asset Impairments	$500	$86	$104

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, below, and Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

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

	Year Ended December 31,		
(millions)	2014	2013	2012
Other Operating (Income) Expense, Net	$38	$43	$25

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

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

	Year Ended December 31,		
(millions)	2014	2013	2012
(Gain) Loss on Commodity Derivative Instruments	$(976)	$133	$(75)
Interest, Net of Amount Capitalized	210	158	125
Other Non-Operating (Income) Expense, Net	(26)	21	6
Total	$(792)	$312	$56

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 7. Derivative Instruments and Hedging Activities and Note 12. Fair Value Measurements and Disclosures, below.

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

	Year Ended December 31,		
(millions, except per unit)	2014	2013	2012
Interest Expense	$326	$279	$276
Capitalized Interest	(116)	(121)	(151)
Interest Expense, Net	$210	$158	$125
Unit Rate per BOE [1]	$1.97	$1.63	$1.48

[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 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. During the year, 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 remained flat in 2013 as compared with 2012. Decreased interest expense related to the repayment of an installment loan was offset by interest expense related to an issuance of new senior debt in November 2013. We drew down amounts under our Credit Facility during third quarter 2013 and repaid with proceeds from the debt issuance. There were no other significant changes in our debt.

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.

The decrease of $30 million in the amount of interest capitalized in 2013 compared with 2012 is due to the completion of major projects at Alen and Tamar, partially offset by higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and offshore Israel.

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 5. 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.

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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, 2014, approximately 38% 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 $25 million in 2014, deferred compensation expense of $26 million in 2013, and deferred compensation expense of $6 million in 2012. See Item 8. Financial Statements and Supplementary Data – Note 11. Stock-Based and Other Compensation Plans

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

	Year Ended December 31,		
(millions)	2014	2013	2012
Income Tax Provision	$496	$437	$391
Effective Rate	29.0 %	32.5 %	28.8 %

See Item 8. Financial Statements and Supplementary Data – Note 10. Income Taxes.

Discontinued Operations

Summarized results of discontinued operations, comprising our North Sea geographical segment during 2012 and 2013, were as follows:

	Year Ended December 31,	
(millions)	2013	2012
Oil and Gas Sales	$37	$208
Less:		
Production Expense	19	44
DD&A Expense	2	33
Other (Income) Expense, Net [1]	4	30
Income Before Income Taxes	12	101
Income Tax Expense	6	55
Operating Income, Net of Tax	6	46
Gain on Sale, Net of Tax	65	16
Discontinued Operations, Net of Tax	$71	$62
Key Statistics:		
Daily Production		
Crude Oil & Condensate (MBbl/d)	1	5
Natural Gas (MMcf/d)	2	4
Average Realized Price		
Crude Oil & Condensate (Per Bbl)	$108.73	$112.94
Natural Gas (Per Mcf)	$10.65	$8.62

(1) Includes exploration expense of $27 million in 2012 related to the Selkirk field, which we determined was uneconomic for joint development.

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. Property Transactions.

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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,		
	2014	2013	2012
(MMBoe)			
Proved Reserves Beginning of Year	1,406	1,184	1,209
Revisions of Previous Estimates	21	95	(97)
Extensions, Discoveries and Other Additions	120	250	218
Purchase of Minerals in Place	—	24	—
Sale of Minerals in Place	(33)	(47)	(57)
Production	(110)	(100)	(89)
Proved Reserves End of Year	1,404	1,406	1,184

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, 2014 include positive performance revisions of 18 MMBoe for the Marcellus Shale program, 4 MMBoe for deepwater Gulf of Mexico, 4 MMBoe for Alba field, and 3 MMBoe for the Tamar field; and 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 price outlook;
- changes for the year ended December 31, 2013 included positive performance revisions of 48 MMBoe for the DJ Basin and Marcellus Shale programs, 11 MMBoe for the Alba field, and 21 MMBoe for the Tamar field; and positive price revisions of 13 MMBoe due to increases in commodity prices; and
- changes for the year ended December 31, 2012 included a negative revision of 94 MMBoe due to our decision to terminate the legacy vertical drilling program in the DJ Basin and focus on horizontal development; net positive revisions of 23 MMBoe, primarily related to better than expected well performance in the Marcellus Shale, the deepwater Gulf of Mexico, and the Aseng field; and negative revisions of 26 MMBoe due to changes in 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, 2014 include 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.
- 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; and
- changes for the year ended December 31, 2012 included an increase of 149 MMBoe in the DJ Basin as a result of our decision to focus capital and resources on horizontal development of the Niobrara formation, 56 MMBoe related to ongoing development of the Marcellus Shale, 7 MMBoe related to the ongoing appraisal of the Tamar field, and 6 MMBoe for other projects.

We expect that a significant portion of future reserves additions will come from our major development projects at the DJ Basin, Marcellus Shale, deepwater Gulf of Mexico, and new discoveries resulting from our active 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.

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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 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 and China assets in 2014;
- the sale of non-core onshore US and North Sea assets and the net impact of the DJ Basin acreage exchange in 2013; and
- the sale of non-core onshore US and North Sea assets in 2012.

See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

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

See also Items 1. and 2. Business and Properties including Update on Core Area – Israel, 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 downturn in crude oil prices. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a continuing exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity.

We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives, while delivering competitive returns and a growing dividend. 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 also consider repatriations of foreign cash to increase our financial flexibility and fund our capital investment program to the extent such cash is not required to fund foreign investment projects and would not incur material incremental US tax. We evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending and may consider other sources of funding.

During 2014, our liquidity position was enhanced by the following activities:

Divestitures Our non-core divestiture program is designed to generate organizational and operational efficiencies as well as cash for use in our capital investment program. Divestitures of non-core properties allow us to allocate capital and employee resources to higher-value and higher-growth areas. Further, proceeds from divestitures provide additional flexibility in the implementation of our international and deepwater Gulf of Mexico exploration and development programs and our horizontal drilling activities in the DJ Basin and Marcellus Shale. Sales of non-core properties generated proceeds of $2.4 billion over the last five years, including $321 million during 2014. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

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.

Public Debt Offering On November 7, 2014, we closed an offering of $1.5 billion senior unsecured notes, at Company-record low coupon levels, the proceeds from which were used to repay the outstanding indebtedness under

our Credit Facility and for general corporate purposes. See Item 8. Financial Statements – Note 9. Long-Term Debt.
Cash Repatriations During 2014, we repatriated $1.3 billion from our foreign operations. We do not expect to incur material incremental US tax on these repatriations due to foreign tax credit usage.

Available Liquidity

Year-end liquidity was as follows:

	December 31,		
	2014	2013	2012
(millions, except percentages)			
Cash and Cash Equivalents	$1,183	$1,117	$1,387
Amount Available to be Borrowed Under Credit Facility [1]	4,000	4,000	4,000
Total Liquidity	$5,183	$5,117	$5,387
Total Debt [2]	$6,197	$4,843	$4,123
Total Shareholders' Equity	10,325	9,184	8,258
Ratio of Debt-to-Book Capital [3]	38 %	35 %	33 %

(1) See Credit Facility, below.

(2) Total debt includes capital lease and other obligations and excludes unamortized debt discount.

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

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Current Activity - Impact on Liquidity
Expanded development in the DJ Basin and Marcellus Shale, investment in major deepwater development projects, and planned exploration and appraisal drilling activities, as well as the fourth quarter 2014 decline in crude oil prices, resulted in capital expenditures exceeding cash flows from operating activities for 2014. The extent to which capital investment will exceed operating cash flows in the future depends on the pace of future DJ Basin and Marcellus Shale 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. In particular, a sustained period of low crude oil prices would have a significant negative impact on our cash flows.
However, our financial capacity, coupled with our 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 – 2015 Capital Investment Program, above.
To support our investment program, we expect that higher production resulting from our core onshore US development programs combined with new production from the Big Bend development project and additional production from the Tamar compression project, will result in an increase in cash flows which will be available to meet a substantial portion of future capital commitments.
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 2015. However, a downgrade or other negative action with respect to our credit rating could exert significant additional liquidity pressures by triggering requirements to post collateral as financial assurance of performance under certain contractual arrangement and/or negatively impact our 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 $1.2 billion in cash and cash equivalents at December 31, 2014, compared with approximately $1.1 billion at December 31, 2013. At December 31, 2014, our cash was primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $600 million of this cash was attributable to foreign subsidiaries. We estimate that there would have been no cash tax impact if this amount had been repatriated at December 31, 2014, due to estimated foreign tax credit usage and our domestic tax position.
Credit Facility   We maintain a Credit Facility with a committed amount of $4.0 billion through 2018. 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, 2014. 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 include variable to fixed price commodity swaps, two and three-way collars and 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.
During fourth quarter 2014, almost one-third of our hedged crude oil volumes were attributable to three-way collars. As crude oil began trading below the strike price of the sold put option contract of the three-way collars during fourth quarter, the cash settlements received by us were limited. However, we still received the cash market price plus the delta between the purchased put option floor price of the two-way collar contract and the sold put option strike price.

Almost half of our 2015 hedged crude oil volumes are attributable to three-way collars. Although three-way collars may limit benefits in low commodity price environments, they allow us to capture more value than swaps or two-way collars in a rising commodity price environment. In addition, the proceeds received from selling the put option contract of the three-way collar allow us to purchase the two-way collar contract with a higher floor price.

As of December 31, 2014, the fair value of our commodity derivative assets was $890 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.

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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 7. 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. Some of these entities are not as creditworthy as we are and may experience credit downgrades or liquidity problems. 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.

In addition, nonoperating partners often must obtain financing for their share of capital cost for development projects. A partner's inability to obtain financing could result in a delay of our joint development projects. For example, our Eastern Mediterranean partners must obtain financing for their share of significant development expenditures at Leviathan, offshore Israel.

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, joint venture partner, 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.

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Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2014	2013	2012
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$3,506	$2,937	$2,933
Investing Activities	(4,465)	(3,675)	(2,527)
Financing Activities	1,025	468	(474)
Increase (Decrease) in Cash and Cash Equivalents	$66	$(270)	$(68)

Operating Activities 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.

Net cash provided by operating activities in 2013 was flat as compared with 2012. Higher commodity sales volumes and higher natural gas prices were offset by a slight decrease in our consolidated average crude oil price, as well as increases in production expenses, general and administrative expense and interest expense.

Investing Activities The primary use of cash in investing activities is for capital spending 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.

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.

Capital spending for property, plant and equipment totaled $3.9 billion in 2013, representing an increase of $297 million as compared with 2012, primarily due to increased 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 as compared with $1.2 billion proceeds from divestitures during 2012.

In 2012, our capital spending totaled $3.7 billion. A significant portion of the spending related to our major project development activity in core areas. We also invested $41 million in CONE during 2012. In addition, we received $1.2 billion proceeds from non-core asset divestitures during 2012.

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 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).

In 2012, net cash used in financing activities was $474 million. Funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($81 million). We used cash to make an installment payment ($328 million), pay dividends on our common stock ($164 million), make principal payments related to a capital lease obligation ($45 million), repurchase shares of our common stock ($13 million) and other ($5 million).

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Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2014	2013	2012
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition (1)	$249	$208	$96
Exploration	505	871	572
Development	3,889	2,996	2,847
Corporate and Other	169	188	70
Total	$4,812	$4,263	$3,585
Other			
Investment in Equity Method Investee (2)	$71	$48	$41
Increase in Capital Lease Obligations (3)	110	76	—

(1) 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.

Unproved property acquisition cost for 2012 includes $85 million in the DJ Basin and other onshore US areas, $25 million related to our entry into a farm-out agreement offshore Falkland Islands, $28 million for deepwater Gulf of Mexico lease blocks, $3 million related to offshore Sierra Leone, offset by downward adjustments related to the Marcellus Shale acquisition.

(2) 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.

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

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.

Total expenditures increased in 2013 as compared with 2012 due to accelerated activity in the DJ Basin and Marcellus Shale, progress on significant development projects offshore Equatorial Guinea and Israel, and increased exploration activity.

Asset Divestitures Non-core asset divestitures generated cash proceeds of $321 million in 2014, $327 million in 2013, and $1.2 billion in 2012.

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 2014.

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.

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In the Gulf of Mexico, we self-insure for windstorm related exposures. 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 $950 million 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 $750 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 $5.8 billion (excluding capital lease and other obligations) at December 31, 2014, with maturities ranging from 2019 to 2097. Our principal source of liquidity is our Credit Facility that matures October 3, 2018. During 2014 and 2013, we drew down and repaid amounts under our Credit Facility for working capital purposes in the normal course of business.

Credit Facility   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, 2014, there were no amounts outstanding under the Credit Facility, leaving the entire $4.0 billion available for use. We expect to use the Credit Facility to fund our 2015 capital investment program, and we periodically borrow amounts for working capital purposes. See Item 8. Financial Statements and Supplementary Data – Note 9. 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.

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During 2013, we completed an underwritten public offering of $1.0 billion of 5.25% senior unsecured notes due November 15, 2043. 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 9. Long-Term Debt.

Fixed-Rate Debt Our outstanding fixed-rate debt (excluding capital lease and other obligations) totaled $5.8 billion at December 31, 2014. The weighted average interest rate on fixed-rate debt was 5.69%, with maturities ranging from 2019 to 2097. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital increased to 38% at December 31, 2014 from 35% at December 31, 2013. Significant changes in our financial position impacting the ratio included the following:

- $971 million net increase in debt; and
- $249 million decrease in shareholders' equity from dividends paid;

offset by:

- $1.2 billion increase in shareholders' equity from current year net income.

Cash Interest Payments We made cash interest payments related to our outstanding debt of $305 million in 2014, $258 million in 2013, and $259 million in 2012.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $48 million in 2014, $51 million in 2013, and $56 million in 2012. 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 68 cents per common share in 2014, 55 cents per common share in 2013, and 45 cents per common share in 2012 (as adjusted for the 2-for-1 stock split during second quarter 2013). On January 27, 2015, the Board of Directors declared a quarterly cash dividend of $0.18 per common share, which will be paid February 23, 2015 to shareholders of record on February 9, 2015. 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 255,000 shares with a total value of $16 million in 2014, 250,000 shares with a total value of $14 million in 2013, and 282,000 shares with a total value of $13 million in 2012.

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, 2014, 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 may agree to an annual plan that provides for more or fewer wells to be drilled than the number of wells that was provided for in the default plan. For 2015, we expect that the amount of capital investment allocated to the Marcellus Shale core area will be less than the amount provided for in the default plan. We and our partner continue to have discussions on the level of joint venture investment in 2015.

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, 2014, 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.

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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, 2014 Henry Hub natural gas price curve, we forecast that the CONSOL Carried Cost Obligation will be suspended in 2015.

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, 2014 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 (millions)	Total	2015	2016 and 2017	2018 and 2019	2020 and beyond
Long-Term Debt (1)	$5,784	$—	$—	$1,000	$4,784
Interest Payments (2)	5,888	329	658	589	4,312
Capital Lease and Other Obligations (3)	610	89	160	137	224
Drilling and Equipment Obligations (4)	362	185	173	4	—
Purchase Obligations (5)	174	131	20	10	13
Transportation and Gathering (6)	2,986	159	425	542	1,860
Operating Lease Obligations (7)	352	49	80	49	174
Other Liabilities (8)					
Asset Retirement Obligations (9)	751	81	209	58	403
Commodity Derivative Instruments (10)	—	—	—	—	—
Total Contractual Obligations	$16,907	$1,023	$1,725	$2,389	$11,770

(1) Long-term debt excludes our capital lease and other obligations. See Item 8. Financial Statements and Supplementary Data – Note 9. Long-Term Debt.

(2) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2014. See Item 8. Financial Statements and Supplementary Data – Note 9. 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 9. 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 and other related equipment for exploratory and development drilling activities. See Counterparty Credit Risk, above, and Item 8. Financial Statements and Supplementary Data – Note 17. 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 17. Commitments and Contingencies.

(6) Transportation and gathering obligations represent minimum charges for firm transportation and gathering agreements related to our production. See Item 8. Financial Statements and Supplementary Data – Note 17. 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 17. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $218 million and accrued benefit costs of $128 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 11. Stock-Based and Other Compensation Plans.

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

(10) There were no open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2014. All our commodity derivative instruments were in a net receivable position at December 31, 2014. See Item 8. Financial Statements and Supplementary Data – Note 7. Derivative Instruments and Hedging Activities.

Exploration Commitments The terms of some of our PSCs, licenses or concession agreements require us to conduct certain exploration activities, including drilling one or more exploratory wells or acquiring seismic data, within specific time periods. At December 31, 2014, we have the following commitments: remaining three-well obligation in Nevada; one-well obligation offshore Cameroon, which we expect to drill later in 2015; one-well obligation offshore Cyprus; one-well obligation offshore

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Falkland Islands; and 3D seismic obligation offshore Gabon. These obligations extend over a period ranging from one to four years. Failure to conduct exploration activities within the prescribed periods could lead to loss of leases or exploration rights.

OIL Contingency As of December 31, 2014, 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, 2014.

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, 2014.

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 downgrade or other negative rating action could affect 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.

Other

Pension Plan Termination We are in the process of terminating our defined benefit pension plan (pension plan). We expect to liquidate the associated pension obligation through lump-sum payments to participants or the purchase of annuities on their behalf.

As of December 31, 2014, the latest actuarial measurement date for the pension plan, the accumulated benefit obligation totaled $287 million, and the fair value of plan assets was $242 million. Therefore, we expect to make additional contributions to the plan of approximately $50 million during the period leading up to final termination and distribution to the extent necessary to fund the net obligation.

In addition, upon termination of the pension plan, all unamortized prior service cost and net actuarial loss remaining in accumulated other comprehensive loss (AOCL) will be charged to expense. This amount totaled approximately $82 million as of December 31, 2014. We expect liquidation of the pension plan to occur in the first half of 2015.

In coordination with the termination of the pension plan, we also amended our restoration plan to freeze the accrual of benefits effective December 31, 2013. 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 may elect to have the lump sum present value of their restoration plan benefits converted into an account balance under our nonqualified deferred compensation plan.

Income Taxes We made cash payments for income taxes, net of refunds, of $150 million in 2014, $165 million in 2013, and $168 million in 2012.

Contingencies Payments to settle legal proceedings totaled approximately $3 million in 2014, $21 million in 2013, and $12 million in 2012. 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 oil and gas 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. In addition, a decline in estimates of proved reserves could prompt a goodwill impairment analysis. 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 2014 when we concluded, based on the results of seismic interpretation, that the Scotia exploratory well drilled offshore Falkland Islands in 2012 was not economically viable.

At December 31, 2014, the balance of property, plant and equipment included $1.3 billion of suspended exploratory well costs, $1.1 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 5. 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

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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 2014, 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 $500 million in 2014, $86 million in 2013 and $104 million in 2012 for proved oil and gas properties and other investments. See Item 8. Financial Statements and Supplementary Data – Note 4. 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 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 2014, 2013 and 2012. No impairment expense was recognized. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Purchase Price Allocations   We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations. 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. Property Transactions.

Goodwill As of December 31, 2014, the consolidated balance sheet included $620 million of goodwill, all of which has been assigned to the US reporting unit. Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. We conducted a qualitative goodwill impairment assessment as of December 31, 2014 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 recent decline in crude oil prices; cost factors that 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 during the second half of 2014. The goodwill recorded to the US reporting unit relates primarily to the excess purchase price over amounts assigned to assets and liabilities from the Patina Merger in 2005. As of December 31, 2014, we have significant excess of our determined US reporting unit market capitalization over the US reporting unit carrying value as our determined market capitalization has significantly increased since 2005. As part of our qualitative goodwill impairment assessment in 2014, we assessed the decrease in commodity prices as compared to our last quantitative assessment. We determined that our determination of fair value of our US reporting unit substantially exceeds its carrying amount using year end 2014 commodity prices.

After assessing the totality of events and circumstances for the qualitative impairment assessment at December 31, 2014, we determined that performing the two-step goodwill impairment test was unnecessary, and no goodwill impairment was recognized.

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 our 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.

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.

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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 it more accurately compares companies using successful efforts and full cost accounting methods, both of which are in our peer group.

Although we base the fair value estimate of the US reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In the event of a prolonged global recession, commodity prices may stay depressed or decline further, thereby causing the fair value of the US reporting unit to decline, which could result in an impairment of goodwill. 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 2014, we sold certain non-core onshore US assets. Goodwill allocated to these assets sold totaled $7 million. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

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 $890 million at December 31, 2014. 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 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, 2014, we reported $947 million for the non-cash portion of gain on commodity derivative instruments.

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 7. Derivative Instruments and Hedging Activities and Note 12. 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 $751 million at December 31, 2014. See Item 8. Financial Statements and Supplementary Data – Note 8. Asset Retirement Obligations.

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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 2014, fourth quarter 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 an additional valuation allowance of $36 million on our available foreign tax credits.

As of December 31, 2014, the accumulated undistributed earnings of our foreign subsidiaries that have been permanently reinvested totaled approximately $3.5 billion. No US taxes have been recorded on these earnings. Management must consider numerous factors in determining timing and amounts of possible future distribution of these earnings to the parent company and whether a US deferred tax liability should be recorded for these earnings. These factors include the future operating and capital requirements of both the parent company and the subsidiaries, 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. This amount is net of estimated foreign tax credits. See Item 8. Financial Statements and Supplementary Data – Note 10. Income Taxes.

A significant portion of our cash is located internationally. We intend to use a significant portion of our international cash to fund international projects, including various exploration projects and the ongoing development and production requirements. However, we estimate that a repatriation of approximately $600 million of cash located outside of the US as of December 31, 2014, would have had no cash tax impact, due to estimated foreign tax credit usage and our domestic tax position. The actual amount of cash repatriated and actual net cash tax impact of such repatriation would depend on our cash and domestic tax positions at the time of repatriation and could be significantly different from this estimate. See Item 8. Financial Statements and Supplementary Data – Note 10. 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, 2014, we had entered into variable to fixed price commodity swaps and three way collars 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, 2014 with a fair value of $890 million. Based on the December 31, 2014 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 $232 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 $36 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 8. Financial Statements and Supplementary Data – Note 7. Derivative Instruments and Hedging Activities.

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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, 2014, we had approximately $5.8 billion (excluding capital lease and other obligations) of long-term debt outstanding. At December 31, 2014, all debt outstanding was fixed-rate debt with a weighted average interest rate of 5.69%. 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 9. 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, 2014, our cash and cash equivalents totaled approximately $1.2 billion, approximately 70% 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 2014, 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 2014, 2013 and 2012. 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.

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Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

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Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. 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, 2014, 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 (1992), 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, 2014, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

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, 2014 which is included herein.

Noble Energy, Inc.

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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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, shareholders’ equity, and cash flows for each of the years in the three year period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2015 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 19, 2015

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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, 2014, based on criteria established in Internal Control - Integrated Framework (1992) 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, 2014, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2014, and our report dated February 19, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 19, 2015

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

	Year Ended December 31,		
	2014	2013	2012
Revenues			
Oil, Gas and NGL Sales	$4,931	$4,809	$4,037
Income from Equity Method Investees	170	206	186
Total Revenues	5,101	5,015	4,223
Costs and Expenses			
Production Expense	958	850	673
Exploration Expense	498	415	409
Depreciation, Depletion and Amortization	1,759	1,568	1,370
General and Administrative	503	433	384
Gain on Divestitures	(73)	(36)	(154)
Asset Impairments	500	86	104
Other Operating (Income) Expense, Net	38	43	25
Total Operating Expenses	4,183	3,359	2,811
Operating Income	918	1,656	1,412
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	(976)	133	(75)
Interest, Net of Amount Capitalized	210	158	125
Other Non-Operating (Income) Expense, Net	(26)	21	6
Total Other (Income) Expense	(792)	312	56
Income from Continuing Operations Before Income Taxes	1,710	1,344	1,356
Income Tax Provision	496	437	391
Income from Continuing Operations	1,214	907	965
Discontinued Operations, Net of Tax	—	71	62
Net Income	$1,214	$978	$1,027
Earnings Per Share, Basic			
Income from Continuing Operations	$3.36	$2.53	$2.71
Discontinued Operations, Net of Tax	—	0.19	0.18
Net Income	$3.36	$2.72	$2.89
Earnings Per Share, Diluted			
Income from Continuing Operations	$3.27	$2.50	$2.68
Discontinued Operations, Net of Tax	—	0.19	0.18
Net Income	$3.27	$2.69	$2.86
Weighted Average Number of Shares Outstanding			
Basic	361	359	356
Diluted	367	363	359

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

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Noble Energy, Inc.
Consolidated Statements of Comprehensive Income
(millions)

	Year Ended December 31,		
	2014	2013	2012
Net Income	$1,214	$978	$1,027
Other Items of Comprehensive Income (Loss)			
Net Change in Pension and Other	42	(6)	(20)
Less Tax (Benefit)	(15)	2	7
Other Comprehensive Income (Loss)	27	(4)	(13)
Comprehensive Income	$1,241	$974	$1,014

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

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Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,183	$1,117
Accounts Receivable, Net	857	947
Commodity Derivative Assets, Current	710	1
Other Current Assets	325	546
Total Current Assets	3,075	2,611
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	25,599	22,243
Property, Plant and Equipment, Other	630	517
Total Property, Plant and Equipment, Gross	26,229	22,760
Accumulated Depreciation, Depletion and Amortization	(8,086)	(7,035)
Total Property, Plant and Equipment, Net	18,143	15,725
Goodwill	620	627
Other Noncurrent Assets	715	679
Total Assets	$22,553	$19,642
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,578	$1,354
Other Current Liabilities	944	988
Total Current Liabilities	2,522	2,342
Long-Term Debt	6,103	4,566
Deferred Income Taxes, Noncurrent	2,516	2,441
Other Noncurrent Liabilities	1,087	1,109
Total Liabilities	12,228	10,458
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; 500 Million Shares Authorized; 402 Million and 400 Million Shares Issued, Respectively	4	4
Additional Paid in Capital	3,624	3,463
Accumulated Other Comprehensive Loss	(90)	(117)
Treasury Stock, at Cost; 38 Million Shares	(671)	(659)
Retained Earnings	7,458	6,493
Total Shareholders' Equity	10,325	9,184
Total Liabilities and Shareholders' Equity	$22,553	$19,642

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

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

	Year Ended December 31,		
	2014	2013	2012
Cash Flows From Operating Activities			
Net Income	$1,214	$978	$1,027
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,759	1,570	1,403
Asset Impairments	500	86	104
Dry Hole Cost	226	149	182
Deferred Income Taxes	268	269	109
Income from Equity Method Investees, Net of Dividends	33	(17)	7
(Gain) Loss on Commodity Derivative Instruments	(976)	133	(75)
Net Cash Received (Paid) in Settlement of Commodity Derivative Instruments	29	(2)	(34)
Gain on Divestitures	(73)	(93)	(72)
Stock Based Compensation	87	80	65
Other Adjustments for Noncash Items Included in Income	27	75	83
Changes in Operating Assets and Liabilities			
(Increase) Decrease in Accounts Receivable	29	(239)	(130)
Increase (Decrease) in Accounts Payable	318	(87)	237
Increase (Decrease) in Current Income Taxes Payable	18	(47)	64
Increase in Other Current Liabilities	45	20	18
Other Operating Assets and Liabilities, Net	2	62	(55)
Net Cash Provided by Operating Activities	3,506	2,937	2,933
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(4,871)	(3,947)	(3,650)
Proceeds from Divestitures	321	327	1,160
Additions to Equity Method Investments	(71)	(48)	(41)
Distributions from Equity Method Investments	156	—	—
Other	—	(7)	4
Net Cash Used in Investing Activities	(4,465)	(3,675)	(2,527)
Cash Flows From Financing Activities			
Exercise of Stock Options	48	51	56
Excess Tax Benefits from Stock-Based Awards	19	20	25
Dividends Paid, Common Stock	(249)	(198)	(164)
Purchase of Treasury Stock	(16)	(14)	(13)
Proceeds from Credit Facilities	1,050	900	150
Repayment of Credit Facilities	(1,050)	(900)	(150)
Proceeds from Issuance of Senior Long-Term Debt, Net	1,478	985	—
Repayment of Senior Notes	(200)	—	—
Repayment of Capital Lease Obligation	(55)	(48)	(45)
Repayment of Installment Loan	—	(328)	(328)
Other	—	—	(5)
Net Cash Provided By (Used in) Financing Activities	1,025	468	(474)
Increase (Decrease) in Cash and Cash Equivalents	66	(270)	(68)
Cash and Cash Equivalents at Beginning of Period	1,117	1,387	1,455

Cash and Cash Equivalents at End of Period	$1,183	$1,117	$1,387

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

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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, 2011	$1,312	$1,841	$(100)	$(638)	$4,850	$7,265
Net Income	—	—	—	—	1,027	1,027
Stock-based Compensation Expense	—	65	—	—	—	65
Exercise of Stock Options	4	52	—	—	—	56
Tax Benefits Related to Exercise of Stock Options	—	25	—	—	—	25
Cash Dividends (45 cents per share)	—	—	—	—	(164)	(164)
Purchase of Treasury Stock	—	—	—	(13)	—	(13)
Change in par value of stock	(1,312)	1,312	—	—	—	—
Rabbi Trust Shares Sold	—	7	—	3	—	10
Net Change in Other	—	—	(13)	—	—	(13)
December 31, 2012	$4	$3,302	$(113)	$(648)	$5,713	$8,258
Net Income	—	—	—	—	978	978
Stock-based Compensation Expense	—	80	—	—	—	80
Exercise of Stock Options	—	51	—	—	—	51
Tax Benefits Related to Exercise of Stock Options	—	20	—	—	—	20
Cash Dividends (55 cents per share)	—	—	—	—	(198)	(198)
Purchase of Treasury Stock	—	—	—	(14)	—	(14)
Rabbi Trust Shares Sold	—	10	—	3	—	13
Net Change in Other	—	—	(4)	—	—	(4)
December 31, 2013	$4	$3,463	$(117)	$(659)	$6,493	$9,184
Net Income	—		—	—	1,214	1,214
Stock-based Compensation Expense	—	87	—	—	—	87
Exercise of Stock Options	—	48	—	—	—	48
Tax Benefits Related to Exercise of Stock Options	—	19	—	—	—	19
Cash Dividends (68 cents per share)	—	—	—	—	(249)	(249)
Purchase of Treasury Stock	—	—	—	(16)	—	(16)
Rabbi Trust Shares Sold	—	7	—	4	—	11
Net Change in Other	—	—	27	—	—	27
December 31, 2014	$4	$3,624	$(90)	$(671)	$7,458	$10,325

[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.

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Noble Energy, Inc.

Notes to Consolidated 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 gas exploration and production. Our core operating areas are onshore US (DJ Basin and Marcellus Shale), 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 6. 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 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 crude oil prices or a significant decline in natural gas 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 and/or goodwill 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 2013 and 2012 consolidated financial statements to conform to the 2014 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 12. 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 oil and 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 2014, 2013, and 2012. 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 4. 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 4. 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. Property Transactions.

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 5. 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 $116 million in 2014, $121 million in 2013, and $151 million in 2012.

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 8. 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 not amortized to earnings but is qualitatively assessed annually in the fourth quarter. If, based on our qualitative procedures, it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we perform the two-step goodwill impairment test. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. No goodwill impairment was indicated at December 31, 2014. However, it is possible that goodwill could become impaired in the future if commodity prices or other economic factors continue to decline.

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. The change in goodwill in 2014 is due to amounts allocated to onshore US properties sold. See Note 3. Property Transactions.

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. Changes in the derivative instrument's fair value are recognized currently in earnings, unless the derivative instrument has been designated as a cash flow hedge and specific cash flow hedge accounting criteria are met. Under cash flow hedge accounting, unrealized gains and losses are reflected in shareholders' equity as accumulated other comprehensive loss (AOCL) until the forecasted transaction occurs. The derivative's gains or losses are then offset against related results on the hedged transaction in the statements of operations.

A company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. When using hedge accounting, we assess hedge effectiveness quarterly based on total changes in the derivative instrument's fair value by performing regression analysis. A hedge is considered effective if certain statistical tests are met. We record hedge ineffectiveness in (gain) loss on commodity derivative instruments.

Accounting for Commodity Derivative Instruments 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.

Accounting for Interest Rate Derivative Instruments We designate interest rate derivative instruments as cash flow hedges. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes.

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 11. 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, 2014 represents unrecognized net actuarial loss and unrecognized prior service cost. 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. See Note 11. 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. See Note 10. 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 Per Share Basic earnings 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 13. Earnings 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 17. 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 14. Segment Information.

Changes in Shareholders' Equity On April 24, 2012, our shareholders voted to approve an amendment to the Company's Certificate of Incorporation to (i) increase the number of authorized shares of our common stock from 250 million to 500 million shares and (ii) reduce the par value of the Company's common stock from $3.33 per share to $0.01 per share. See the Consolidated Statements of Shareholders' Equity.

Recently Issued Accounting Standards In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. Early adoption is permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. We elected to early adopt ASU 2014-08 on a prospective basis, and the adoption did not have a material impact on our consolidated financial statements.

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. The amendments in

ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and early application is not permitted. We are currently evaluating the provisions of ASU 2014-09 and awaiting implementation guidance to determine the impact, if any, it may have on our financial position and results of operations.

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Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Production Expense			
Lease Operating Expense	$604	$530	$431
Production and Ad Valorem Taxes	184	188	151
Transportation Expense	170	132	91
Total	$958	$850	$673
Other Operating Expense, Net			
Gathering, Marketing, and Processing Expense, Net	$16	$36	$23
Other, Net	22	7	2
Total	$38	$43	$25
Other Non-Operating (Income) Expense, Net			
Deferred Compensation (Income) Expense [1]	$(25)	$26	$6
Other (Income) Expense, Net	(1)	(5)	—
Total	$(26)	$21	$6

[1] Amounts represent increases (decreases) in the fair value of shares of our common stock held in a rabbi trust.

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Additional balance sheet information is as follows:

(millions)	December 31, 2014	2013
Accounts Receivable, Net		
Commodity Sales	$405	$495
Joint Interest Billings	297	382
Other	171	81
Allowance for Doubtful Accounts	(16)	(11)
Total	$857	$947
Other Current Assets		
Inventories, Materials and Supplies	$81	$96
Inventories, Crude Oil	24	25
Deferred Income Taxes, Net, Current	—	62
Assets Held for Sale	180	292
Prepaid Expenses and Other Assets, Current	40	71
Total	$325	$546
Other Noncurrent Assets		
Equity Method Investments	$325	$437
Mutual Fund Investments	111	114
Commodity Derivative Assets, Noncurrent	180	16
Other Assets, Noncurrent	99	112
Total	$715	$679
Other Current Liabilities		
Production and Ad Valorem Taxes	$110	$103
Commodity Derivative Liabilities, Current	—	65
Income Taxes Payable - Current	180	156
Income Taxes Payable - Deferred	158	—
Asset Retirement Obligations, Current	81	39
Accrued Benefit Costs, Current	125	10
Interest Payable	70	63
Current Portion of Long Term Debt	—	200
Current Portion of Capital Lease and Other Obligations	68	58
Liabilities Associated with Assets Held for Sale	9	111
Other Liabilities, Current	143	183
Total	$944	$988
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$218	$253
Asset Retirement Obligations, Noncurrent	670	547
Accrued Benefit Costs, Noncurrent	24	155
Other Liabilities, Noncurrent	175	154
Total	$1,087	$1,109

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Supplemental statements of cash flow information is as follows:

(millions)	Year Ended December 31, 2014	2013	2012
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$189	$137	$107
Income Taxes Paid, Net	150	165	168
Non-Cash Financing and Investing Activities			
Increase in Capital Lease and Other Obligations	110	96	—

Note 3. Property Transactions

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, including our Piceance, Tri-State, and Powder River properties. The information regarding the assets sold is as follows:

(millions)	Year Ended December 31, 2014	2013	2012
Cash Proceeds	$135	$150	$1,044
Less			
Net Book Value of Assets Sold	(150)	(117)	(836)
Goodwill Allocated to Assets Sold	(7)	(8)	(61)
Asset Retirement Obligations Associated with Assets Sold	48	8	20
Other Closing Adjustments	10	3	(13)
Gain on Divestitures	$36	$36	$154

We continue to market non-core onshore US properties; certain of these assets, as discussed below, met the criteria for reclassification as assets held for sale at December 31, 2014.

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:

(millions)	Year Ended December 31, 2014 2014
Sales Proceeds	$186
Less	
Net Book Value of Assets Sold	(149)
Other Closing Adjustments	(2)
Gain on Divestiture	$35

Assets Held for Sale Assets held for sale as of December 31, 2014 include non-core onshore US assets ($105 million) in the DJ Basin and two natural gas discoveries, Tanin and Karish, offshore Israel ($75 million). Regarding Tanin and Karish, we agreed to divest these assets pursuant to an agreement we and our partners reached with the Israeli Antitrust Authority in March 2014 on various antitrust matters. See also Note 5. Capitalized Exploratory Well Costs.

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 2012 and 2013, we sold the majority of our non-operated, North Sea properties. The 2013 sales resulted in a $65 million gain based on net sales proceeds of $56 million. In 2012, proceeds from sales totaled $117 million, the net book value of assets sold was $255 million, and associated asset retirement obligations were $55 million. We also reversed a deferred tax liability and recognized a corresponding income tax benefit of $99 million related to the sale. During 2012 and 2013, the North Sea geographical segment was presented as discontinued operations in our consolidated statements of operations.

We were unable to locate purchasers for the remaining properties. 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 4. Asset Impairments.

Summarized results of discontinued operations are as follows:

	Year Ended December 31,	
(millions)	2013	2012
Oil and Gas Sales	$37	$208
Income Before Income Taxes [1]	12	101
Income Tax Expense	6	55
Operating Income, Net of Tax	6	46
Gain on Sale, Net of Tax	65	16
Discontinued Operations, Net of Tax	$71	$62

[1] Income before income taxes for 2012 includes exploration expense of $27 million related to the Selkirk field which was determined uneconomic for joint development.

Note 4. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Onshore US	$42	$39	$39
Deepwater Gulf of Mexico	350	—	34
Eastern Mediterranean	14	47	31
North Sea	94	—	—
Total	$500	$86	$104

2014 Asset Impairments During 2014, certain onshore US and deepwater Gulf of Mexico 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 $250 million resulted from declines in crude oil prices at year end 2014.

During 2013, 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

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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.

2012 Asset Impairments Due to declines in realized natural gas prices associated with an onshore US property, and declines in near-term crude oil prices associated with a deepwater Gulf of Mexico property, we determined that their carrying amounts were not recoverable from future cash flows and, therefore, were impaired. In addition, due to end-of-field life declines in production, offshore Israel, we determined that the carrying amount was not recoverable from future cash flows and, therefore, was impaired. The assets were written down to their estimated fair values, which were determined using a discounted cash flow model, as described above.

See also Note 12. Fair Value Measurements and Disclosures.

Note 5. 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)	2014	2013	2012
Capitalized Exploratory Well Costs, Beginning of Period	$1,301	$900	$696
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	316	581	360
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale[1]	(196)	(177)	(18)
Capitalized Exploratory Well Costs Charged to Expense [2]	(84)	(3)	(114)
Other [3]	—	—	(24)
Capitalized Exploratory Well Costs, End of Period	$1,337	$1,301	$900

(1) The 2014 amount primarily relates to the Dantzler well (deepwater Gulf of Mexico), for which we sanctioned a development plan, and the Tanin and Karish 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 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 2012 amount primarily represents deepwater Gulf of Mexico exploratory well costs.

(3) The 2012 amount relates to North Sea exploratory well costs included in discontinued operations. See Note 3. Property Transactions.

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)	2014	2013	2012
Exploratory Well Costs Capitalized for a Period of One Year or Less	$247	$568	$355
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	1,090	733	545
Balance at End of Period	$1,337	$1,301	$900
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	13	13	14

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The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of December 31, 2014:

Country/Project (millions)	Total	Suspended Since 2012 - 2013	2010 - 2011	2009 & Prior	Progress
Onshore US					
Northeast Nevada	23	23	—	—	Analyzing results from our first four exploratory vertical wells and evaluating potential for production tests
Deepwater Gulf of Mexico					
Troubadour	47	47	—	—	Evaluating development scenarios for this 2013 natural gas discovery including subsea tieback to existing infrastructure
Offshore Equatorial Guinea					
Diega (Block O) and Carmen (Block I)	216	111	52	53	Evaluating regional development scenarios for this 2008 crude oil discovery. We drilled subsequent appraisal wells. During 2014, conducted additional seismic activity over Blocks O and I and are engaged in processing the newly-acquired seismic data.
Carla (Block O)	149	137	12	—	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.
Felicita (Block O)	39	4	6	29	Evaluating regional development plans for this 2008 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.
Yolanda (Block I)	20	3	3	14	Evaluating regional development plans for 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. In addition, we are working to finalize a data exchange agreement between the two countries.
Offshore Cameroon					
YoYo	47	4	9	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 (1)					
Leviathan	181	71	110	—	During 2014, we received the Leviathan Development and Production Leases, submitted a development plan to the government and engaged in natural gas marketing activities. We are working to resolve antitrust and other regulatory matters with the Israeli government.
Leviathan-1 Deep	78	51	27	—	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	26	4	2	20	Submitted a development plan to the government to develop this 2009 natural gas discovery as a tie-in to existing infrastructure.
Dolphin 1	25	3	22	—	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					

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Cyprus	196	139	57	—	Discussing monetization options with the Cyprus government for this 2011 natural gas discovery. In May 2014, our application for renewal of the PSC for two additional years was approved. We plan to submit a plan of development to the government in 2015.
Other					
Projects less than $20 million	43	33	4	6	Continuing to drill and evaluate wells
Total	$1,090	$630	$304	$156	

(1) In March 2014, we and our partners reached an agreement with the Israel Antitrust Authority on various matters (Consent Decree). The Consent Decree, which was subject to final approval by the Antitrust Tribunal, granted the rights, to us and our partners, to jointly market natural gas from the Leviathan field. Also as a result of the Consent Decree, we agreed to divest our Tanin and Karish natural gas discoveries. However, on December 23, 2014, we and our partners in the Leviathan field were advised by the Israel Antitrust Authority of its decision to not submit the Consent Decree to the Antitrust Tribunal for final approval. This is a matter that we believed was resolved some time ago and we had received recent assurances from the Antitrust Authority that approval was forthcoming. We requested an oral hearing with the Antitrust Authority, which took place on January 27, 2015, and await final disposition.

Note 6. 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)	2014	2013
Equity Method Investments		
AMPCO	$141	$139
Alba Plant	82	95
CONE Investments[1]	82	184
Other	20	19

Total Equity Method Investments	$325	$437

(1) CONE Investments includes our investments in CONE Midstream and CONE Gathering.

Other At December 31, 2014, consolidated retained earnings included $100 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, 2014. 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)	2014	2013
Balance Sheet Information		
Current Assets	$412	$463
Noncurrent Assets	1,169	983
Current Liabilities	374	373
Noncurrent Liabilities	33	29

	Year Ended December 31,		
(millions)	2014	2013	2012
Statements of Operations Information			
Operating Revenues	$1,142	$1,256	$1,173
Operating Expenses	405	388	361
Operating Income	737	868	812
Other (Income) Net	(9)	(14)	(5)
Income Before Income Taxes	746	882	817
Income Tax Provision	172	212	200
Net Income	$574	$670	$617

Note 7. 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 with respect to a portion of our expected production. The derivative instruments we use may include variable to fixed price commodity swaps, two-way and three-way collars, basis swaps and 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, 2014.

We also may enter into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing.
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.

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See Note 12. 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, 2014, we had entered into the following crude oil derivative instruments:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of December 31, 2014							
2015	Swaps	NYMEX WTI	27,000	$88.80	$—	$—	$—
2015	Swaps	Dated Brent	8,000	100.31	—	—	—
2015	Three-Way Collars	NYMEX WTI	20,000	—	70.50	87.55	94.41
2015	Three-Way Collars	Dated Brent	13,000	—	76.92	96.00	108.49
2016	Swaps	NYMEX WTI	6,000	87.95	—	—	—
2016	Swaps	Dated Brent	9,000	97.96	—	—	—
2016	Three-Way Collars	NYMEX WTI	3,000	—	72.00	85.00	94.82
2016	Three-Way Collars	Dated Brent	6,000	—	80.00	95.00	105.87

As of December 31, 2014, we had entered into the following natural gas derivative instruments:

Settlement Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of December 31, 2014							
2015	Swaps	NYMEX HH	140,000	$4.30	$—	$—	$—
2015	Three-Way Collars	NYMEX HH	150,000	—	3.58	4.25	5.04

2016	Swaps	NYMEX HH	10,000	3.90	—	—	—
2016	Three-Way Collars	NYMEX HH	30,000	—	3.00	3.75	4.40

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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, 2014		December 31, 2013		December 31, 2014		December 31, 2013	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments	Current Assets	$710	Current Assets	$1	Current Liabilities	$—	Current Liabilities	$65
	Noncurrent Assets	180	Noncurrent Assets	16	Noncurrent Liabilities	—	Noncurrent Liabilities	10
Total		$890		$17		$—		$75

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

	Year Ended December 31,		
(millions)	2014	2013	2012
(Gain) Loss on Commodity Derivative Instruments			
Crude Oil	$(897)	$139	$(37)
Natural Gas	(79)	(6)	(38)
Total (Gain) Loss on Commodity Derivative Instruments	(976)	133	(75)
Cash (Received) Paid in settlement of Commodity Derivative Instruments			
Crude Oil	(34)	52	83
Natural Gas	5	(50)	(49)
Total Cash (Received) Paid in settlement of Commodity Derivative Instruments	(29)	2	34
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments			
Crude Oil	(863)	87	(120)
Natural Gas	(84)	44	11
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	$(947)	$131	$(109)

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Note 8. Asset Retirement Obligations
Asset retirement obligations (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Year Ended December 31,	
(millions)	2014	2013
Asset Retirement Obligations, Beginning Balance	$586	$402
Liabilities Incurred	75	90
Liabilities Settled	(101)	(41)
Revision of Estimate	155	156
Accretion Expense	36	28
Other	—	(49)
Asset Retirement Obligations, Ending Balance	$751	$586

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 a 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 and included $33 million for DJ Basin, $29 million for the 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.
For the year ended December 31, 2013
Liabilities incurred were due to new wells and facilities and included $15 million for onshore US development, $68 million for deepwater Gulf of Mexico, and $7 million for Eastern Mediterranean.
Liabilities settled of $41 million primarily related to deepwater Gulf of Mexico abandonment activities and non-core, onshore US assets sold.
Revisions were primarily due to changes in estimated costs for future abandonment activities and acceleration of timing and included $86 million for DJ Basin, $36 million for deepwater Gulf of Mexico, $10 million for Equatorial Guinea, and $7 million for Eastern Mediterranean. Increased US costs are due primarily to more stringent abandonment standards impacting procedures and materials.
Other includes $17 million for non-core, onshore US, and $32 million for China ARO liabilities transferred to liabilities associated with assets held for sale.
See Note 2. Additional Financial Statement Information and Note 3. Property Transactions.
Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 9. Long-Term Debt
Our debt consists of the following:

(millions, except percentages)	December 31, 2014 Debt	Interest Rate		December 31, 2013 Debt	Interest Rate	
Credit Facility, due October 3, 2018	$—	—		$—	—	
Capital Lease and Other Obligations	413	—		359	—	
5.25% Senior Notes, due April 15, 2014 [1]	—	—		200	5.25	%
8.25% Senior Notes, due March 1, 2019	1,000	8.25	%	1,000	8.25	%
4.15% Senior Notes, due December 15, 2021	1,000	4.15	%	1,000	4.15	%
7.25% Senior Notes, due October 15, 2023	100	7.25	%	100	7.25	%
3.90% Senior Notes, due November 15, 2024	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	%	—	—	
7.25% Senior Debentures, due August 1, 2097	84	7.25	%	84	7.25	%
Total	6,197			4,843		
Unamortized Discount	(26)			(19)		
Total Debt, Net of Discount	6,171			4,824		
Less Amounts Due Within One Year						
Current Portion of Long Term Debt, Net of Discount	—			(200)		
Capital Lease and Other Obligations	(68)			(58)		
Long-Term Debt Due After One Year	$6,103			$4,566		

[1] We repaid the senior notes on their due date.

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 $50 million remain and are being amortized to expense over the life of the related debt issues and are included in current and long-term assets based on their related debt terms.

Credit Facility On October 3, 2013, we amended our $4.0 billion Credit Facility to extend the maturity date to October 3, 2018. We periodically borrow amounts for working capital purposes.

Our Credit Facility (i) provides for facility fee rates that range from 12.5 basis points to 30 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 100 basis points to 145 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, 2014, 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.

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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, with total debt issuance costs of approximately $15 million being amortized to expense over the terms of the notes. 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.

2013 Debt Offering On November 8, 2013, we closed an offering of $1.0 billion senior unsecured notes receiving net proceeds of $985 million, after deducting discount and underwriting fees. The notes are due November 15, 2043, and pay interest semi-annually at 5.25%. Total debt issuance costs of approximately $6 million were incurred and are being amortized to expense over the term of the notes. Approximately $900 million 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 17. 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, 2014	
2015	$—
2016	—
2017	—
2018	—
2019	1,000
Thereafter	4,784
Total	$5,784

Note 10. Income Taxes

Components of income from continuing operations before income taxes are as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Domestic	$282	$202	$92
Foreign	1,428	1,142	1,264
Total	$1,710	$1,344	$1,356

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The income tax provision from continuing operations consists of the following:

	Year Ended December 31,		
(millions)	2014	2013	2012
Current Taxes			
Federal	$19	$21	$14
State	1	1	1
Foreign	208	144	143
Total Current	228	166	158
Deferred Taxes			
Federal	237	96	60
State	13	1	1
Foreign	18	174	172
Total Deferred	268	271	233
Total Income Tax Provision	$496	$437	$391
Effective Tax Rate	29.0 %	32.5 %	28.8 %

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
(percentages)	2014	2013	2012
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	(3.3)	(5.3)	(4.9)
State Taxes, Net of Federal Benefit	0.8	0.1	0.2
Difference Between US and Foreign Rates	(14.2)	(6.3)	(4.9)
Foreign Exploration Loss	—	2.7	(3.8)
Change in Valuation Allowance	1.9	3.8	4.3
Oil Profits Tax - Israel	0.2	0.3	0.9
Tax Contingency	0.1	0.4	1.8
Non Permanent Reinvestment on Foreign Earnings	8.2	—	—
Other, Net	0.3	1.8	0.2
Effective Rate	29.0	32.5	28.8

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Deferred tax assets and liabilities resulted from the following:

(millions)	December 31, 2014	2013
Deferred Tax Assets		
Loss Carryforwards	$170	$174
Employee Compensation & Benefits	149	143
Foreign Tax Credits	67	31
Other	51	56
Total Deferred Tax Assets	437	404
Valuation Allowance - Foreign Loss Carryforwards	(145)	(135)
Valuation Allowance - Foreign Tax Credits	(67)	(31)
Valuation Allowance - Capital Loss Carryforwards	(1)	(2)
Net Deferred Tax Assets	224	236
Deferred Tax Liabilities		
Mark to Market of Commodity Derivative Instruments	(209)	—
Non-Permanent Reinvestment of Foreign Earnings	(141)	—
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,548)	(2,615)
Total Deferred Tax Liability	(2,898)	(2,615)
Net Deferred Tax Liability	$(2,674)	$(2,379)

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

(millions)	December 31, 2014	2013
Deferred Income Tax Asset - Current	$—	$62
Deferred Income Tax Liability - Current	(158)	—
Deferred Income Tax Liability - Noncurrent	(2,516)	(2,441)
Net Deferred Tax Liability	$(2,674)	$(2,379)

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, 2014. 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 $145 million in 2014 and $135 million in 2013. 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 fourth quarter 2014, fluctuations in oil and 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 non-permanent reinvested foreign earnings and a corresponding valuation allowance of $36 million on our foreign tax credits.

During 2013, as a result of execution of tax planning strategies, we reversed a $27 million deferred tax asset for future foreign tax credits from our foreign branch operations along with the corresponding valuation allowance. Additionally, we recorded a $20 million valuation allowance on excess foreign tax credits.

Effective Tax Rate 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.

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Our effective tax rate increased in 2013 as compared with 2012 primarily due to a change in the funding of foreign exploration projects and an increase in the Israeli corporate income tax rate. The increase was partially offset by a release of the valuation allowance on foreign tax credits utilized on the 2012 tax return, a change to the tax contingencies, and an increase in the difference between the higher US statutory rate and lower statutory rates in jurisdictions where we are generating income, including Israel and Equatorial Guinea.

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.

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2014, the accumulated undistributed earnings of the foreign subsidiaries that have been permanently reinvested were approximately $3.5 billion. No US taxes have been recorded on these earnings. Upon distribution of earnings classified as permanently reinvested in the form of dividends or otherwise, we would likely be subject to US income taxes and foreign withholding taxes. It is not practicable, however, to determine precisely the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of US foreign tax credits. The actual tax impact would depend on our tax positions at the time of payment and could be significantly different from this estimate. Although we are currently claiming foreign tax credits, we may not be in a credit position when any future remittance of foreign earnings takes place, or the limitations imposed by the Internal Revenue Code and IRS Regulations may not allow the credits to be utilized during the applicable carryback and carryforward periods. However, if full use of tax credits is assumed, we estimate that the future US taxes on eventual remittance would be approximately $850 million.

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 - 2011, Equatorial Guinea - 2009 and Israel - 2010.

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, 2014
Unrecognized Tax Benefits, Beginning Balance	$28
Additions for Tax Positions Related to Current Year	—
Additions for Tax Positions of Prior Years	4
Reductions for Tax Positions of Prior Years	(3)
Settlements	—
Unrecognized Tax Benefits, Ending Balance	$29

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 the twelve months ended December 31, 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 the year ended December 31, 2014, we recognized and accrued a de minimis amount of interest and none in penalties.

As of December 31, 2013, approximately $28 million of unrecognized tax benefits would impact our effective tax rate if recognized. The changes to our unrecognized tax benefits during the twelve months ended December 31, 2013 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 the year ended December 31, 2013, 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 11. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
(millions)	2014	2013	2012
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$63	$58	$48
Exploration Expense and Other	24	22	17
Total Stock-Based Compensation Expense	$87	$80	$65
Tax Benefit Recognized	$(31)	$(28)	$(23)

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 71,600,000 shares of common stock. At December 31, 2014, 32,962,380 shares of our common stock were reserved for issuance, including 14,380,862 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.

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, 2014, 1,359,832 shares of our common stock were reserved for issuance, including 843,285 shares available for future grants and awards under the 2005 Plan.

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 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)	2014	2013	2012
Expected Term (in Years)	5.9	5.7	5.7
Expected Volatility	35.1 %	36.4 %	37.0 %
Risk-Free Rate	1.8 %	1.1 %	0.9 %
Expected Dividend Yield	1.1 %	1.2 %	1.2 %
Weighted Average Grant-Date Fair Value	$20.31	$17.08	$15.99

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, 2013	12,677,857	$39.82		
Granted	2,186,232	62.61		
Exercised	(1,459,490)	32.39		

Forfeited	(396,277)	56.47		
Outstanding at December 31, 2014	13,008,322	$43.98	5.9	$97
Exercisable at December 31, 2014	8,993,726	$37.20	4.8	$97

The total intrinsic value of options exercised was $58 million in 2014, $64 million in 2013, and $72 million in 2012. As of December 31, 2014, $39 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, 2014	Year Ended December 31, 2013
Number of Simulations	500,000	500,000
Expected Volatility	30 %	30 %
Risk-Free Rate	0.7 %	0.4 %

Restricted stock activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Shares	Weighted Average Award Date Fair Value (per share)	Number of Shares	Weighted Average Award Date Fair Value (per share)
Outstanding at December 31, 2013	1,487,869	$50.74	848,026	$28.93
Awarded	441,647	62.87	797,792	29.24
Vested	(796,877)	49.30	—	—
Forfeited	(83,839)	55.27	(127,482)	29.08
Outstanding at December 31, 2014	1,048,800	$55.68	1,518,336	$29.10

The total fair value of restricted stock that vested was $50 million in 2014, $43 million in 2013, and $47 million in 2012.

The weighted average award-date fair value of restricted stock awarded was $41.22 per share in 2014, $38.07 per share in 2013, and $50.75 per share in 2012.

As of December 31, 2014, $38 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 1.4 years 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 $26 million in 2014, $21 million in 2013, and $17 million in 2012.

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)	2014	2013
Rabbi Trust Assets		
Mutual Fund Investments	$83	$88
Noble Energy Common Stock (at Fair Value)	51	88
Total Rabbi Trust Assets	134	176
Liability Under Related Deferred Compensation Plan	$134	$176
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	1,073,286	1,292,335

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 12. 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 1,000,000 shares, or 93%, of our common stock held in respect of one nonqualified deferred compensation plan at December 31, 2014 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next five years. Distributions of 200,000 shares were made in 2014 and 200,000 shares in 2013. In addition, plan participants sold 19,049 shares of our common stock in 2014, 1,008 shares in 2013, and 4,536 shares in 2012. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $22 million in 2014, $25 million in 2013 and $19 million in 2012.

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 $(25) million in 2014, $26 million in 2013 and $6 million in 2012.

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 $84 million, $77 million and $70 million were outstanding at December 31, 2014, 2013 and 2012, 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 provides the pension plan formula benefits that cannot 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.

We are in the process of terminating the pension plan. We expect to liquidate the associated pension obligation through lump-sum payments to participants or the purchase of annuities on their behalf. As of December 31, 2014, the latest actuarial measurement date for the pension plan, the accumulated benefit obligation totaled $287 million, and the fair value of plan assets was $242 million. We expect to make additional contributions to the plan during the period leading up to final termination and distribution to the extent necessary to fund the net obligation.

In addition, upon termination of the pension plan, all unamortized prior service cost and net actuarial loss remaining in AOCL will be charged to expense. This amount totaled $82 million at December 31, 2014. We expect liquidation of the pension plan to occur in the first half of 2015.

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 may elect to have the lump sum present value of their restoration plan benefits converted into an account balance under our nonqualified deferred compensation plan.

We also curtailed the retiree medical program during 2014, resulting in a gain of $21 million and 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		Medical and Life Plans	
(millions)	2014	2013	2014	2013
Pension or Other Benefit Obligation	$(363)	$(394)	$(7)	$(36)
Fair Value of Plan Assets	242	265	—	—
Net Amount Recognized in Consolidated Balance Sheet	(121)	(129)	(7)	(36)
Current Liabilities	(102)	(6)	(2)	(2)
Noncurrent Liabilities	(19)	(123)	(5)	(34)
Net Prior Service (Cost) Credit, Before Tax	$(75)	$(88)	$2	$6
Net Gains (Losses), Before Tax	(42)	(56)	—	(15)
Accumulated Other Comprehensive Income (Loss)	$(117)	$(144)	$2	$(9)

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 $11 million in 2014, $37 million in 2013, and $27 million in 2012.

Note 12. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

Mutual Fund Investments   Our mutual fund investments, which primarily include assets held in a rabbi trust, 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 consist of variable to fixed price commodity swaps, two-way and/or three-way collars. We estimate the fair values of these instruments based on 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 7. 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.

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

(millions)	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Adjustment [2]	Fair Value Measurement
December 31, 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)
December 31, 2013					
Financial Assets					
Mutual Fund Investments	$114	$—	$—	$—	$114
Commodity Derivative Instruments	—	28	—	(11)	17
Financial Liabilities					
Commodity Derivative Instruments	—	(86)	—	11	(75)
Portion of Deferred Compensation Liability Measured at Fair Value	(176)	—	—	—	(176)

(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:

Asset Impairments We determined that the carrying amounts of certain 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:

Description	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Net Book Value [2]	Total Pre-tax (Non-cash) Impairment Loss
(millions)					
Year Ended December 31, 2014					
	$—	$—	$100	$600	$500

Impaired Oil and Gas Properties					
Year Ended December 31, 2013					
Impaired Oil and Gas Properties	—	—	113	199	86
Year Ended December 31, 2012					
Impaired Oil and Gas Properties	—	—	228	332	104

(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 4. Asset Impairments.

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Additional Fair Value Disclosures

See Note 9. Long-Term Debt. Fair value information regarding our debt is as follows:

	December 31, 2014		December 31, 2013	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net of Unamortized Discount (1)	$5,758	$6,179	$4,465	$4,959

(1) Excludes capital lease and other obligations. No floating rate debt was outstanding at December 31, 2014 or December 31, 2013. See Note 9. Long-Term Debt.

Note 13. Earnings Per Share

Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings 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 per share:

	Year Ended December 31,		
(millions, except per share amounts)	2014	2013	2012
Income from Continuing Operations	$1,214	$907	$965
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust (1)	(17)	—	—
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$1,197	$907	$965
Weighted Average Number of Shares Outstanding, Basic	361	359	356
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	6	4	3
Weighted Average Number of Shares Outstanding, Diluted	367	363	359
Earnings from Continuing Operations Per Share, Basic	$3.36	$2.53	$2.71
Earnings from Continuing Operations Per Share, Diluted	3.27	2.50	2.68
Additional Information			
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	3	5
Weighted average option exercise price per share	$60.30	$53.40	$48.73

(1) 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 per share calculations for the year ended December 31, 2014 excludes deferred compensation gains, net of tax.

Note 14. 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, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Gabon, Sierra Leone, and Senegal/Guinea-Bissau (which we exited in 2012); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, China (through June 2014), Falkland Islands, Nicaragua and new ventures. The North Sea geographical segment is included in continuing operations in 2014 and 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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	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
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	620	620	—	—	—
Total Assets at End of Year [2]	22,553	16,400	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	627	627	—	—	—
Total Assets at End of Year [2]	19,598	13,094	3,199	2,753	552
Year Ended December 31, 2012					
Revenues from Third Parties [1]	$4,037	$2,339	$1,343	$178	$177
Income from Equity Method Investees	186	—	186	—	—
Total Revenues	4,223	2,339	1,529	178	177
DD&A	1,370	929	255	111	75
Asset Impairments	104	73	—	31	—
Gain on Divestitures	(154)	(154)	—	—	—
(Gain) Loss on Commodity Derivative Instruments	(75)	(76)	1	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,356	806	1,074	9	(533)
Equity Method Investments	367	121	230	—	16
Additions to Long-Lived Assets	3,525	2,046	447	869	163
Goodwill at End of Year	635	635	—	—	—
Total Assets at End of Year [2]	17,509	11,199	3,063	2,572	675

(1) Revenues from third parties for all foreign countries, in total, were $1.8 billion in both 2014 and 2013, and $1.7 billion in 2012.
(2) Long-lived assets located in all foreign countries, in total, were $4.4 billion, $4.5 billion, and $4.2 billion at December 31, 2014, 2013, and 2012, respectively.

Note 15. 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, 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	%
Year Ended December 31, 2012				
Glencore Energy UK Ltd	39	%	31	%
Shell [1]	17	%	14	%

[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 protected through guarantees or credit support. Nonperformance by a trade creditor could result in losses.

Our increased level of 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.

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Note 16. Additional Shareholders' Equity Information

Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31, 2014	2013
Common Stock Shares Issued		
Shares, Beginning of Period	399,841,717	396,697,484
Exercise of Common Stock Options	1,459,490	1,892,962
Restricted Stock Awards, Net of Forfeitures	1,028,118	1,251,271
Shares, End of Period	402,329,325	399,841,717
Treasury Stock		
Shares, Beginning of Period	37,600,051	37,550,752
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	254,888	250,307
Rabbi Trust Shares Distributed and/or Sold	(219,049)	(201,008)
Shares, End of Period	37,635,890	37,600,051

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, 2011	$(26)	$(74)	$(100)
Realized Amounts Reclassified Into Earnings	1	6	7
Unrealized Change in Fair Value	—	(20)	(20)
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)

All amounts in the table above are reported net of tax, using an effective income tax rate of 35%.

AOCL at December 31, 2014 included deferred losses of $23 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 17. 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.

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, 2014.

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, 2014 NYMEX Henry Hub natural gas price curve, we forecast the CONSOL Carried Cost Obligation will be suspended in 2015.

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 $69 million in 2014, $50 million in 2013, and $37 million in 2012.

Minimum commitments as of December 31, 2014 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations	Operating Lease Obligations	Capital Lease and Other Obligations(1)	Total
2015	$316	$159	$49	$89	$613
2016	137	185	40	78	440
2017	56	240	40	82	418
2018	11	277	31	86	405
2019	3	265	18	51	337
2020 and Thereafter	13	1,860	174	224	2,271
Total	$536	$2,986	$352	$610	$4,484

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 9. 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, 2014, 2013, and 2012 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. 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, 2014. 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, Sierra Leone, and Senegal/Guinea-Bissau (which we exited in 2012); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, China (through June 2014), Falkland Islands, Nicaragua and new ventures. The North Sea geographical segment is included in continuing operations in 2014 and discontinued operations in 2013 and 2012.

Operations in Cyprus, Equatorial Guinea, Gabon and Sierra Leone 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 Nicaragua, 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.

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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).

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Proved Oil Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved crude oil reserves:

	Crude Oil and Condensate (MMBbls)			
	United States	Equatorial Guinea	Other Int'l [1]	Total
Proved Reserves as of:				
December 31, 2011	171	87	19	277
Revisions of Previous Estimates [2]	(58)	9	—	(49)
Extensions, Discoveries and Other Additions [3]	93	1	1	95
Purchase of Minerals in Place [4]	—	—	—	—
Sale of Minerals in Place [5]	(17)	—	(4)	(21)
Production [6]	(18)	(13)	(3)	(34)
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
Proved Developed Reserves as of				
December 31, 2011	86	48	13	147
December 31, 2012	87	48	8	143
December 31, 2013	102	64	8	174
December 31, 2014	119	52	3	174
Proved Undeveloped Reserves as of				
December 31, 2011	85	38	6	129
December 31, 2012	83	35	5	123
December 31, 2013	134	12	2	148
December 31, 2014	117	13	—	130

(1) Other International includes China (through June 2014) , the North Sea and Israel.

(2) The 2012 US revisions were primarily attributable to our decision to terminate the legacy vertical drilling program in the DJ Basin and focus on the horizontal development of the Niobrara formation. Equatorial Guinea revisions were associated with performance revisions for the Aseng field.

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.

(3) The 2012 increase in US reserves included an increase of 98 MMBbls in the DJ Basin and 8 MMBbls from Marcellus Shale development. International increases were due primarily to additional development in China.

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 2013 increase is attributable to the acquisition of additional acreage in the Marcellus Shale and other onshore US locations.
(4) In 2012, we sold non-core, onshore US and North Sea assets.
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.
(5) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2014, 2013 and 2012.
See also Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. Property Transactions.

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Proved Gas Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (Bcf)				
	United States	Equatorial Guinea	Israel [1]	Other Int'l [2]	Total
Proved Reserves as of:					
December 31, 2011	1,976	786	2,269	12	5,043
Revisions of Previous Estimates [3]	(266)	2	(24)	—	(288)
Extensions, Discoveries and Other Additions [4]	601	16	42	—	659
Purchase of Minerals in Place [5]	—	—	—	—	—
Sale of Minerals in Place [6]	(164)	—	—	(2)	(166)
Production	(160)	(86)	(37)	(1)	(284)
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
Proved Developed Reserves as of					
December 31, 2011	1,195	497	83	11	1,786
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
Proved Undeveloped Reserves as of					
December 31, 2011	781	289	2,186	1	3,257
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

(1) We are working with the Israeli government to reach agreement on various regulatory matters. See Items 1. and 2. Business and Properties – Update on Core Area – Israel.

(2) Other International includes China (through June 2014) and the North Sea. See Note 3. Property Transactions.

(3) The 2012 US revisions were primarily attributable to our decision to terminate the legacy vertical drilling program in the DJ Basin and focus on the horizontal development of the Niobrara formation, and negative price revisions due to lower natural gas prices, partially offset by improved well performance in the Marcellus Shale. Israel revisions were due to performance revisions in the Mari-B field.

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.

(4) The 2012 increase in US reserves included 305 Bcf in the DJ Basin and 291 Bcf in the Marcellus Shale. The Equatorial Guinea increase was due to additions at Aseng, and the Israel increase was due to additional appraisal activity at Tamar.

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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.

(5) The 2013 increase is attributable to the acquisition of additional acreage in the Marcellus Shale and other onshore US locations.

(6) In 2012, we sold non-core, onshore US and North Sea assets.

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.

See also Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs). See also Note 3. Property Transactions.

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Proved NGL Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved NGL reserves:

	NGLs (MMBbls)			
	United States	Equatorial Guinea	Other Int'l	Total
Proved Reserves as of:				
December 31, 2011	73	19	—	92
Revisions of Previous Estimates	1	—	—	1
Extensions, Discoveries and Other Additions (1)	12	—	—	12
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place	(8)	—	—	(8)
Production	(6)	(2)	—	(8)
December 31, 2012	72	17	—	89
Revisions of Previous Estimates	6	2	—	8
Extensions, Discoveries and Other Additions (1)	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 (1)	18	—	—	18
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place	—	—	—	—
Production	(7)	(3)	—	(10)
December 31, 2014	113	15	—	128
Proved Developed Reserves as of				
December 31, 2011	49	11	—	60
December 31, 2012	42	12	—	54
December 31, 2013	44	11	—	55
December 31, 2014	64	8	—	72
Proved Undeveloped Reserves as of				
December 31, 2011	24	8	—	32
December 31, 2012	30	5	—	35
December 31, 2013	51	7	—	58
December 31, 2014	49	7	—	56

(1) The 2012 additions in US reserves included an increase of 5 MMBbls in the DJ Basin and 7 MMBbls from Marcellus Shale development.
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.
See also Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs).

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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:

(millions)	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
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
Year Ended December 31, 2012					
Revenues	$2,339	$1,343	$178	$384	$4,244
Production Costs [2]	539	105	31	105	780
Exploration Expense	225	3	—	210	438
DD&A	929	255	111	75	1,370
Asset Impairments	73	—	31	—	104
Income before Income Taxes	573	980	5	(6)	1,552
Income Tax Expense [3]	201	245	4	74	524
Results of Operations [4]	$372	$735	$1	$(80)	$1,028

(1) Other International includes the North Sea, China (through June 30, 2014), Cameroon, Gabon, Sierra Leone, Cyprus, Nicaragua, Falkland Islands, and other new ventures. See Note 3. Property Transactions.

(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) During 2014, 2013 and 2012, we incurred exploration expense in currently non-commercial 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 7. Derivative Instruments and Hedging Activities.

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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, 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
Year Ended December 31, 2012					
Property Acquisition Costs					
Unproved [3]	68	—	—	28	96
Exploration Costs [4]	335	56	125	173	689
Development Costs [5]	1,839	366	718	70	2,993
Total Consolidated Operations	$2,242	$422	$843	$271	$3,778
Company's Share of CONE Gathering Development Costs	$55	$—	$—	$—	$55

(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, and Falkland Islands. See Note 3. Property Transactions.

(3) 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.

2012 unproved property acquisition costs for the US include: $63 million related to expanding our position in the DJ Basin, $28 million for deepwater Gulf of Mexico lease blocks, and $27 million related to other onshore US, offset by a downward purchase price adjustments of $50 million related to our Marcellus Shale acquisition. 2012 unproved property acquisition costs for Other International include $25 million related to our position in Falkland Islands.

(4) 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.

2012 exploration costs include drilling and completion of $36 million in the DJ Basin, $40 million in Equatorial Guinea, $102 million in Israel, $13 million in Cyprus and $71 million in Falkland Islands.

(5) Worldwide development costs include amounts spent to develop PUDs of approximately $2.0 billion in 2014, $1.0 billion in 2013 and $1.8 billion in 2012.

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US development costs include increases in asset retirement obligations of $106 million in 2014, $214 million in 2013 and $73 million in 2012. EG development costs include increases in asset retirement obligations of $34 million in 2014, $9 million in 2013 and $1 million in 2012. Israel development costs include increases in asset retirement obligations of $19 million in 2014, $14 million in 2013 and $54 million in 2012. Other International development costs include increases in asset retirement obligations of $71 million in 2014, $9 million in 2013 and $17 million in 2012.

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,	
	2014	2013
(millions)		
Unproved Oil and Gas Properties [1]	$1,487	$1,463
Proved Oil and Gas Properties [2]	24,112	21,195
Total Oil and Gas Properties	25,599	22,658
Accumulated DD&A [3]	(7,820)	(7,082)
Net Capitalized Costs	$17,779	$15,576
Company's Share of CONE Gathering Net Capitalized Costs	$290	$179

(1) Unproved oil and gas properties include amounts remaining from the allocation of costs to unproved properties acquired in previous acquisitions, primarily the Marcellus Shale, of $655 million and $860 million at December 31, 2014 and 2013, respectively.

(2) Proved oil and gas properties at December 31, 2014 include assets held for sale of $105 million related to non-core onshore US assets and $75 million related to two natural gas discoveries, Tanin and Karish, offshore Israel, and asset retirement costs of $639 million.

Proved oil and gas properties at December 31, 2013 include assets held for sale of $323 million related to China and $88 million related to the North Sea, and asset retirement costs of $501 million.

(3) Accumulated DD&A at December 31, 2013 includes $187 million related to China assets held for sale and $50 million related to North Sea assets held for sale. See Note 3. Property Transactions.

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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, 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
December 31, 2012					
Future Cash Inflows [3]	$23,495	$10,318	$14,608	$1,171	$49,592
Future Production Costs [4]	6,531	2,148	942	487	10,108
Future Development Costs [5]	5,372	417	440	177	6,406
Future Income Tax Expense	3,622	1,811	2,568	166	8,167
Future Net Cash Flows	7,970	5,942	10,658	341	24,911
10% Annual Discount for Estimated Timing of Cash Flows	3,506	1,750	6,523	51	11,830
Standardized Measure of Discounted Future Net Cash Flows	$4,464	$4,192	$4,135	$290	$13,081

(1) We are working with the Israeli government to reach agreement on various regulatory matters. See Items 1. and 2. Business and Properties – Update on Core Area – Israel.
(2) Other International includes China (through June 30, 2014) and the North Sea. See Note 3. Property Transactions.
(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 8. Asset Retirement Obligations.

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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, 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	66.60	—	—	40.98
December 31, 2012					
Average Crude Oil and Condensate Price per Bbl	$89.22	$100.97	$105.38	$114.54	$94.40
Average Natural Gas Price per Mcf	2.66	0.25	6.36	6.77	3.99
Average NGL Price per Bbl	40.11	67.54	—	—	40.11

(1) Other International includes China (through June 2014) and the North Sea. See Note 3. Property Transactions.

Because the discounted future net cash flows are computed using a 12-month average commodity price applied to our year-end quantities of proved reserves, the significant decline in crude oil prices at the end of 2014 is not fully reflected in our discounted future net cash flows. 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 2014 would reduce the discounted future net cash flows before income taxes by approximately $2.5 billion. We estimate that a $0.50 per Mcf reduction in the average price of natural gas from the 12-month average price for 2014 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 $2.2 billion in 2015, $1.8 billion in 2016 and $1.7 billion in 2017.

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,		
	2014	2013	2012
(millions)			
Imbalance Receivables	$34	$31	$29
Imbalance Liabilities	33	29	25

Imbalance receivables and imbalance liabilities have been excluded from the standardized measure of discounted future net cash flows.

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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,		
	2014	2013	2012
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$14,090	$13,081	$13,289
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(4,027)	(3,937)	(3,463)
Net Changes in Prices and Production Costs	(1,090)	(237)	(1,902)
Extensions, Discoveries and Improved Recovery, Less Related Costs	1,457	3,386	1,811
Changes in Estimated Future Development Costs	(2,179)	(1,825)	1,042
Development Costs Incurred During the Period	4,042	3,195	2,988
Revisions of Previous Quantity Estimates	162	1,541	(1,256)
Purchases of Minerals in Place	—	78	—
Sales of Minerals in Place	(268)	(768)	(1,141)
Accretion of Discount	1,919	1,765	1,860
Net Change in Income Taxes	671	(780)	732
Change in Timing of Estimated Future Production and Other	(798)	(1,409)	(879)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	(111)	1,009	(208)
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$13,979	$14,090	$13,081

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)					
2014 [1]					
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
Discontinued Operations, Net of Tax	—	—	—	—	—
Net Income	200	192	419	402	1,214
Basic Earnings Per Share [3]					
Income from Continuing Operations	$0.56	$0.53	$1.16	$1.11	$3.36
Discontinued Operations, Net of Tax	—	—	—	—	—
Net Income	0.56	0.53	1.16	1.11	3.36
Diluted Earnings Per Share [3] [4]					
Income from Continuing Operations	$0.55	$0.52	$1.12	$1.05	$3.27
Discontinued Operations, Net of Tax	—	—	—	—	—
Net Income	0.55	0.52	1.12	1.05	3.27
2013 [2]					
Revenues	$1,143	$1,149	$1,394	$1,328	$5,015
Income from Continuing Operations Before Income Taxes	318	486	311	229	1,344
Income from Continuing Operations	232	358	195	122	907
Discontinued Operations, Net of Tax	29	19	10	12	71
Net Income	261	377	205	134	978
Basic Earnings Per Share [3]					
Income from Continuing Operations	$0.65	$1.00	$0.54	$0.34	$2.53
Discontinued Operations, Net of Tax	0.08	0.05	0.03	0.04	0.19
Net Income	0.73	1.05	0.57	0.38	2.72
Diluted Earnings Per Share [3] [4]					
Income from Continuing Operations	$0.65	$0.99	$0.53	$0.33	$2.50
Discontinued Operations, Net of Tax	0.08	0.05	0.03	0.04	0.19
Net Income	0.73	1.04	0.56	0.37	2.69

[1] First quarter 2014 included the following:

- $75 million loss on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $42 million (See Note 7. Derivative Instruments and Hedging Activities);
- $1 million pre-tax loss on sale of non-core assets (See Note 3. Property Transactions); and
- $97 million impairment charges (See Note 4. Asset Impairments).

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 7. Derivative Instruments and Hedging Activities);
- $42 million pre-tax gain on sale of non-core assets (See Note 3. Property Transactions); and
- $34 million impairment charges (See Note 4. Asset Impairments).

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 7. Derivative Instruments and Hedging Activities);
- $30 million pre-tax gain on sale of non-core assets (See Note 3. Property Transactions); and
- $33 million impairment charges (See Note 4. Asset Impairments).

Supplemental Quarterly Financial Information
(Unaudited)

Fourth quarter 2014 included the following:

- $903 million gain on commodity derivative instruments, including the non-cash portion of the gain on commodity derivative instruments of $779 million (See Note 7. Derivative Instruments and Hedging Activities);
- $2 million pre-tax gain on sale of non-core assets (See Note 3. Property Transactions); and
- $36 million impairment charges (See Note 4. Asset Impairments).

(2) First quarter 2013 included the following:

- $72 million loss on commodity derivative instruments, including non-cash portion of the loss on commodity derivative instruments of $79 million (See Note 7. Derivative Instruments and Hedging Activities); and
- $12 million pre-tax gain on sale of non-core assets (See Note 3. Property Transactions).

Second quarter 2013 included the following:

- $161 million gain on commodity derivative instruments, including the non-cash portion of the gain on commodity derivative instruments of $159 million (See Note 7. Derivative Instruments and Hedging Activities).

Third quarter 2013 included the following:

- $157 million loss on commodity derivative instruments, including the non-cash portion of the loss on commodity derivative instruments of $147 million (See Note 7. Derivative Instruments and Hedging Activities); and
- $63 million impairment charges (See Note 4. Asset Impairments).

Fourth quarter 2013 included the following:

- $65 million loss on commodity derivative instruments, including the non-cash portion of loss on commodity derivative instruments of $64 million (See Note 7. Derivative Instruments and Hedging Activities);
- $24 million pre-tax gain on sale of non-core assets (See Note 3. Property Transactions); and
- $23 million impairment charges (See Note 4. Asset Impairments).

(3) 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.

(4) 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.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures 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, 2014. Based on our assessment, our internal controls over financial reporting were effective. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

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 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

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.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NOBLE ENERGY, INC.
(Registrant)

Date: February 19, 2015	By: /s/ David L. Stover David L. Stover, President, Chief Executive Officer
Date: February 19, 2015	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date: February 19, 2015	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	President, Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2015
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 19, 2015
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 19, 2015
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board and Director	February 19, 2015
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 19, 2015
/s/ Michael A. Cawley Michael A. Cawley	Director	February 19, 2015
/s/ Edward F. Cox Edward F. Cox	Director	February 19, 2015
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 19, 2015
/s/ Eric P. Grubman	Director	February 19, 2015

Eric P. Grubman

/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 19, 2015
/s/ Scott D. Urban Scott D. Urban	Director	February 19, 2015
/s/ William T. Van Kleef William T. Van Kleef	Director	February 19, 2015
/s/ Molly K. Williamson Molly K. Williamson	Director	February 19, 2015

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INDEX TO EXHIBITS

Exhibit Number		Exhibit **
2.1	—	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc. including Annex 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).
3.1	—	Certificate of Incorporation, as amended through April 23, 2013, of the Registrant (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 and incorporated herein by reference).
3.2	—	By-Laws of Noble Energy, Inc. as amended through April 23, 2013 (filed as Exhibit 3.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 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 Event: 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% Senior 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 Event: 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 Event: 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 Event: 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 Event: 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 Event: November 4, 2014) filed November 7, 2014 and incorporated herein by reference).

4.9	—	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).
4.10	—	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 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.11	—	First Indenture Supplement dated as of April 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 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).

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4.12	—	Second Indenture Supplement, dated as of August 1, 1997, to Indenture dated as of April 1, 1997, between the Company 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 Event: 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	—	$3.0 billion five-year 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 Event: 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., 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 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 Event: October 3, 2013) filed October 9, 2013 and incorporated herein by reference).
10.8*	—	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).
10.9*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.10*	—	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).
10.11*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (effective September 1, 2008) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 and incorporated herein by reference).
10.12*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. dated effective March 17, 2011 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: March 17, 2011) filed March 22, 2011 and incorporated herein by reference).
10.13*	—	

		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 Event: January 27, 2009) filed on February 2, 2009 and incorporated herein by reference).
10.14*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference).
10.15*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 23, 2013) (filed as Exhibit 10.1 to Registrant's Registration Statement (Registration No. 333-191878) on Form S-8 filed October 24, 2013 and incorporated herein by reference).
10.16*	—	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).

10.17*	—	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 Event: February 1, 2011), filed February 4, 2011 and incorporated herein by reference).
10.18*	—	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).
10.19*	—	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 Event: February 1, 2011), filed February 4, 2011 and incorporated herein by reference).
10.20*	—	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 Event: October 21, 2014), filed October 27, 2014 and incorporated herein by reference).
10.21*	—	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).
10.22*	—	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 Event: December 20, 2013) filed December 23, 2013 and incorporated herein by reference).
10.23*	—	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).
10.24*	—	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 Event: December 20, 2013) filed December 23, 2013 and incorporated herein by reference).
10.25	—	Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. and 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).
10.26	—	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, and 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).
10.27	—	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 Event: September 28, 2012), filed October 2, 2012 and incorporated herein by reference).
10.28	—	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 Event: September 28, 2012), filed October 2, 2012 and incorporated herein by reference).
10.29*	—	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).
10.30*	—	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 Event: February 19, 2014), filed February 25, 2014 and incorporated herein by reference).
10.31*	—	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 Event: August 14, 2014), filed August 19, 2014 and incorporated herein by reference).
10.32*	—	Form of 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).
10.33*	—	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).

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10.34*	—	Form of Restricted Stock Agreement (for inducement 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).
10.35*	—	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).
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.
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.

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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