noble energy

Standing for the **Future**

2013 ANNUAL REPORT

Our ability to execute, agility to navigate a changing landscape and capacity to drive positive change enables us to stand for what is in the best interest of all stakeholders – including our shareholders, our communities, our employees, our partners and our industry – now and in the future.

Powered by a Unique Design

PURPOSE

LEADERSHIP

STRATEGY

2020 & Beyond

A unique strategy rooted in a common purpose provides a clear vision of future success.

ASSETS

EXECUTION

GROWTH

Thinking Differently

Our commitment to doing things right advances our purpose – *Energizing the World, Bettering People's Lives.*

Charles D. Davidson
Chairman of the Board
and Chief Executive Officer

The aggressive execution of our strategy in 2013 delivered strong results on all fronts – successful startups of major projects, production growth at double-digit rates, new exploration discoveries and a leading safety record. As a result, we closed the year at record levels of risked resources and proven reserves after delivering a 35 percent total return to you, our shareholders. 2013 will not stand alone as we expect to continue to deliver sustainable, material growth for many years into the future through the development of major exploration discoveries and unconventional U.S. resources.

Our ability to execute, agility to navigate a changing landscape and capacity to drive positive change enables us to stand for what is in the best interest of all stakeholders – including our shareholders, our communities, our employees, our partners and our industry – now and in the future. This drives our vision to be the world's energy partner of choice.

Key accomplishments during the year included – initial production at Tamar offshore Israel only two-and-a-half years from sanction and first production at Alen offshore Equatorial Guinea ahead of schedule. Onshore U.S., we implemented the next generation of production systems with the startup of the first Integrated Development Plan in the DJ Basin, while continuing to expand our Marcellus operations. Our future growth was further solidified through four new exploration discoveries and six additional major projects sanctioned for future development. It is accomplishments such as these that contribute to our strong growth outlook for the future.

It is clear that we are providing for tomorrow's growth today. Proven reserves during the year grew 19 percent and, after adding discovered unbooked resources, our total discovered resources grew to 7.8 billion barrels of oil equivalent. Based on total 2013 produced volumes of 100 million barrels of oil equivalent, this translates to more than 75 years of production. This places us in an enviable position of having unique visibility to our five-year plan that projects we will more than double our production by 2018.

Our total return to shareholders included an increased dividend, further reflecting our confidence in the future. Overall, annual cash dividends have increased 67 percent in the last five years after adjusting for our stock split. Our balance sheet and liquidity remain strong, thus helping ensure our ability to deliver the future. Our portfolio enhancement continued during the year with the divestiture of non-core assets, yielding net proceeds of $206 million. This program not only helps strengthen us financially, but also enables us to increase our focus on growth opportunities.

Our intense focus on listening to the needs of the communities and concerns of the public are key elements in building trust where we operate. This commitment was evident in the strategic initiatives we implemented. From advancing environmental regulations to malaria control projects and after-school programs, we are committed to safe, responsible operations and bettering people's lives in all our communities. I would encourage you to learn more about our sustainability, transparency and social responsibility initiatives which can be found in our annual Sustainability Report and on our website.

Visible Leader

>75

YEARS OF DISCOVERED RESOURCES

$6B

MARKET CAP INCREASE IN ONE YEAR

0.59

LEADING SAFETY RECORD

Total Recordable Incident Rate (includes company and contractors)

18%

ANNUAL PRODUCTION GROWTH THROUGH 2018

A BRIGHT FUTURE

5 Core Operating Areas

Exceptional Execution

Successful delivery of major projects provides tomorrow's growth today.

First Integrated Development Plan at Wells Ranch in the DJ Basin

Tamar producing 2.5 years after sanction offshore Israel

Alen sanction to startup in 30 months offshore Equatorial Guinea

Aseng startup 7 months ahead of schedule

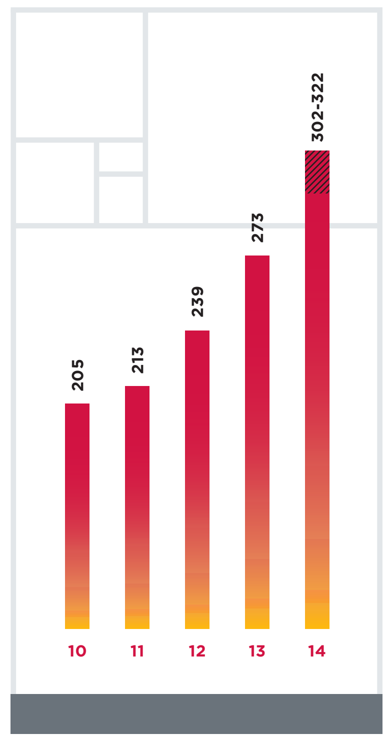
Our operations continue to focus on five core areas. In the U.S., they are the DJ Basin in the Rockies, Marcellus Shale in the Northeast and the deepwater Gulf of Mexico. Our international core areas are in West Africa offshore Equatorial Guinea and Cameroon and in the Eastern Mediterranean offshore Israel and Cyprus. During the year, we also pursued new venture opportunities in Nevada, the Falkland Islands, Nicaragua and Sierra Leone. Our new ventures program is designed to identify and secure new positions that, if successful, have the potential to develop into new core areas for the company.

The DJ Basin delivered 35 percent of total sales volumes in 2013. We have exclusively focused our drilling program there on horizontal wells, primarily in the Niobrara formation. We brought on our first Integrated Development Plan (IDP) in the Wells Ranch area while sanctioning a second at East Pony. Several more are in the design phase. IDPs enable us to lower costs, accelerate development and reduce environmental impacts. As a result, efficiencies and returns increased and project performance and delivery were enhanced. During the year, we drilled a total of nearly 300 development wells, a 50 percent increase compared to 2012. Technology additions, such as field-wide automation systems, also help us operate more safely and efficiently. These systems performed well as we prepared for, responded to and recovered from the severe floods that struck Colorado in September. The focus of our employees on the protection of human health and the environment was impressive – but their efforts extended far beyond the boundaries of our operations to the very heart of the impacted communities nearby.

We further enhanced the value of this premier asset with a strategic acreage exchange of approximately 50,000 acres. This exchange will help us better optimize drilling activities, increase use of extended-reach lateral wells, centralize facilities, streamline operations and reduce our land footprint.

Noble Energy continues to drive positive change in Colorado through non-traditional collaboration. During 2013, we engaged with state, environmental and industry partners to develop recommendations for new air rules governing oil and gas operations. These rules are expected to significantly reduce hydrocarbon emissions in Colorado, thus enhancing the state's air quality. We also made significant progress in our efforts to respond to the Colorado community's need for information about oil and natural gas development. We worked with industry partners to establish Coloradans for Responsible Energy Development (CRED), a 501c6 organization designed to educate communities about hydraulic fracturing.

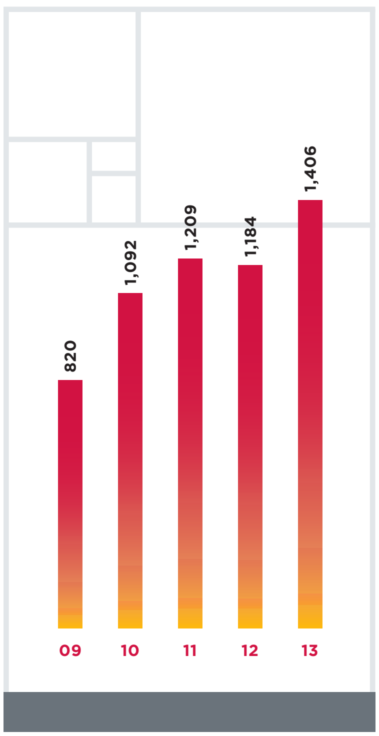
In our second year of operations in the Marcellus Shale, we experienced significant growth with these operations delivering 9 percent of our total sales volumes. We acquired our position in the Marcellus in 2011 through the formation of a 50/50 joint venture (JV) with CONSOL Energy. During 2013, with CONSOL, we acquired an additional 90,000 gross acres in West Virginia, thus expanding the JV's position to a total of 700,000 gross acres. Within the JV, Noble Energy's operations are focused in the wet gas area while our partner operates in the dry gas area. With a deep inventory of drilling opportunities, we expect our Marcellus production to grow at a compound annual growth rate of 46 percent over the next five years.



Sales Volumes from Continuing Operations
(MBoe/d)

Transparent Growth

Through a unique combination of diverse assets, innovative processes and strong leadership, Noble Energy is positioned for enduring growth.



Year-end Proved Reserves
(MMBoe)

The deepwater Gulf of Mexico continues to highlight the value of our exploration program with two new discoveries at Troubadour and Dantzler. Also during the year, we drilled a successful second appraisal well at Gunflint that allowed us and our partners to move forward with the sanctioning of development. We also sanctioned our 2012 Big Bend discovery for development. These discoveries add significant value to our overall portfolio. First production from these major projects is anticipated in 2015 from Big Bend and in 2016 from Gunflint and Dantzler.

Shifting to our international operations – Israel delivered 13 percent of our total sales volumes in 2013. In March 2013, we initiated production from the Tamar field just two-and-a-half years after sanction. Tamar's performance has been outstanding, with gross production since startup averaging 750 MMcf/d and peak production hitting 1 Bcf/d during periods of high demand.

During the year, we drilled two additional gas discoveries at Karish and Tamar Southwest. Tamar Southwest was immediately sanctioned for development and will be produced utilizing Tamar infrastructure. Earlier in the year, the Tamar expansion project was sanctioned, which will enhance the peak deliverability of the field. Since our first drilling in Israel in 1999, Noble Energy has discovered approximately 40 Tcf in the Mediterranean. Leviathan, the largest discovery in 2010, created an opportunity for Israel to become an exporter of energy. Israel finalized an export policy that was one of the critical elements needed for us to move forward with Leviathan. We expect full field development to involve several phases, and multiple development options are underway. The agreement that provides for Woodside Petroleum Ltd. to enter the project also continues to progress. The value of Woodside's LNG expertise and financial capacity will be a strategic addition to the development of Leviathan.

Our West Africa operations continue to strongly contribute to our success and delivered 29 percent of our total sales volumes in 2013. During the year, the Alen development began production early and is performing well. Equatorial Guinea represents our longest-running international business. We are the only oil and natural gas company that has maintained a continuous presence there for more than 20 years.

To better position us for the future, we continue to build and develop an outstanding organization. As part of this effort, we expanded our leadership team to assure that we have the skilled resources to manage our rapid growth in the coming years. Early in the year we were pleased that Molly Williamson, currently a scholar at the Middle East Institute and former senior U.S. State Department official, joined us as a director. Her expertise brings further enhancement to Noble Energy's highly skilled and experienced Board of Directors.

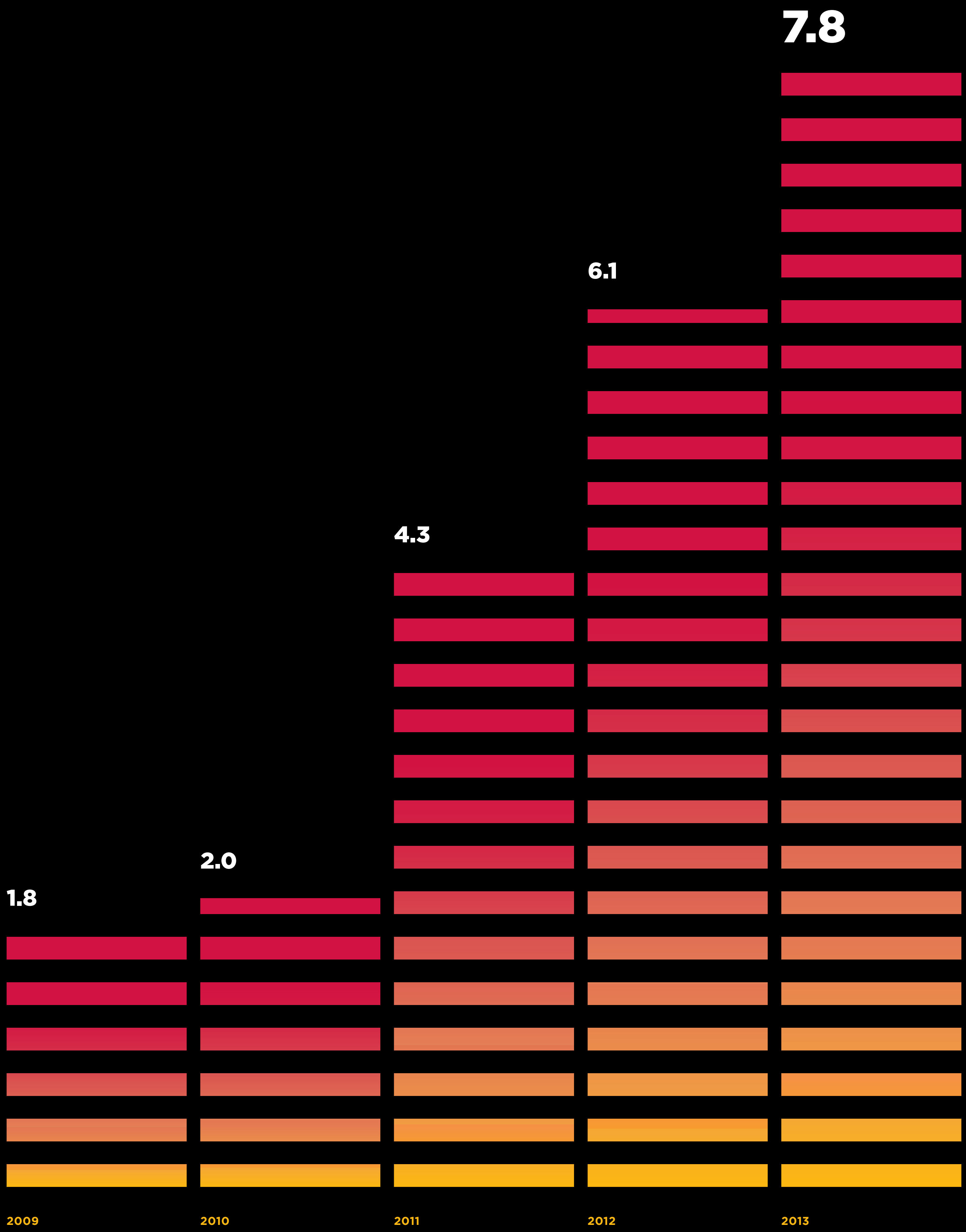
We clearly understand that delivery of our future plans fully depends on exceptional execution by our employees. I greatly appreciate their commitment to the delivery of value through safe, responsible operations, financial discipline and community engagement.

On behalf of the Board of Directors and our employees, I want to thank all of our stakeholders for their continued confidence and support of Noble Energy.

Charles D. Davidson
Chairman and CEO

Discovered Resources (BBoe)

(Discovered unbooked resources plus proven reserves)



Operating and Financial Data

Operating Data	**2013**	2012	2011	2010	2009
Year-end Proved Reserves					
Liquids (MMBbls)	**435**	357	369	365	336
Natural Gas (Bcf)	**5,828**	4,964	5,043	4,361	2,904
Total (MMBoe)	**1,406**	1,184	1,209	1,092	820
Sales Volumes from Continuing Operations					
Liquids (MBbl/d) [1]	**123**	109	78	75	73
Natural Gas (MMcf/d)	**901**	774	806	781	776
Total (MBoe/d)	**273**	239	213	205	202
Average Sales Price					
Crude Oil and Condensate (per Bbl) [2]	**$ 100.29**	$ 101.52	$ 99.17	$ 75.76	$ 55.32
Natural Gas (per Mcf)	**$ 2.97**	$ 2.19	$ 3.00	$ 2.98	$ 2.52

Financial Data (In millions, except per share amounts and ratios)	**2013**	2012	2011	2010	2009
Revenues	**$ 5,015**	$ 4,223	$ 3,404	$ 2,713	$ 2,160
Income (Loss) from Continuing Operations [3]	**$ 907**	$ 965	$ 412	$ 631	$ (159)
Net Income (Loss) [3]	**$ 978**	$ 1,027	$ 453	$ 725	$ (131)
Income (Loss) from Continuing Operations per Share Diluted [4]	**$ 2.50**	$ 2.68	$ 1.15	$ 1.78	$ (0.46)
Net Income (Loss) per Share Diluted [4]	**$ 2.69**	$ 2.86	$ 1.27	$ 2.05	$ (0.38)
Weighted Average Shares Diluted [4]	**363**	359	357	354	347
Cash Dividends per Share [4]	**$ 0.55**	$ 0.45	$ 0.40	$ 0.36	$ 0.36
Net Cash Provided by Operating Activities	**$ 2,937**	$ 2,933	$ 2,170	$ 1,946	$ 1,508
Capital Expenditures [5]	**$ 4,311**	$ 3,626	$ 3,024	$ 2,143	$ 1,317
Total Assets	**$ 19,642**	$ 17,554	$ 16,444	$ 13,282	$ 11,807
Total Debt	**$ 4,824**	$ 4,108	$ 4,469	$ 2,272	$ 2,037
Stockholders' Equity	**$ 9,184**	$ 8,258	$ 7,265	$ 6,848	$ 6,157
Total Debt-to-Book-Capital Ratio	**35%**	33%	38%	25%	25%
Debt per Boe	**$ 3.43**	$ 3.47	$ 3.70	$ 2.08	$ 2.48

[1] Includes sales from equity method investees

[2] Excludes equity method investees

[3] See Reconciliation of Net Income (Loss) to Adjusted Earnings per the company's earnings releases

[4] Amounts adjusted for the 2-for-1 stock split which occurred in 2013

[5] Excludes non-cash increase in capital lease obligations and corporate acquisitions

DIRECTORS AND OFFICERS

Directors

Charles D. Davidson (4)
Chairman of the Board and Chief Executive Officer, Noble Energy, Inc.

Jeffery L. Berenson (2) (3)
President and Chief Executive Officer, Berenson & Company

Michael A. Cawley (1) (3)
Retired Trustee, President and Chief Executive Officer, The Samuel Roberts Noble Foundation, Inc.

Edward F. Cox (2) (3) (4)
Retired Partner, Patterson Belknap Webb & Tyler LLP

Thomas J. Edelman (2) (3) (4)
Managing Partner, White Deer Energy LP

Eric P. Grubman (1) (3)
Executive Vice President, National Football League

Kirby L. Hedrick (2) (3) (4)
Former Executive Vice President, Phillips Petroleum Company

Scott D. Urban (1) (3) (4)
Former Group Vice President, BP

William T. Van Kleef (1) (3)
Former Executive Vice President and Chief Operating Officer, Tesoro Corporation

Molly K. Williamson (2) (3) (4)
Scholar with the Middle Eastern Institute

Committee Membership

(1) Audit Committee

(2) Compensation, Benefits and Stock Option Committee

(3) Corporate Governance and Nominating Committee

(4) Environment, Health and Safety Committee

Executive Officers

Charles D. Davidson
Chairman of the Board and Chief Executive Officer

David L. Stover
President and Chief Operating Officer

Kenneth M. Fisher
Executive Vice President and Chief Financial Officer

Ted D. Brown
Senior Vice President and Advisor to the CEO and President

Rodney D. Cook*
Senior Vice President and Advisor to the CEO and President

Susan M. Cunningham
Senior Vice President, Gulf of Mexico, West Africa and Frontier

J. Keith Elliott
Senior Vice President, Eastern Mediterranean

Arnold J. Johnson
Senior Vice President, General Counsel and Secretary

John T. Lewis
Senior Vice President, Corporate Development

Mike Putnam
Vice President, Exploration and Geoscience

Charles J. (Chip) Rimer
Senior Vice President, Global Operations and EHS&R

Andrea Lee Robison
Senior Vice President, Human Resources and Administration

Gary W. Willingham
Senior Vice President, US Onshore

* Retired March 31, 2014

CORPORATE INFORMATION

Annual Meeting
The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 22, 2014, at 9:30 a.m. Central Time, at The Woodlands Waterway Marriott Hotel & Convention Center located at 1601 Lake Robbins Drive, The Woodlands, Texas 77380. All stockholders are cordially invited to attend.

Form 10-K
The company's Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission (SEC), is included in this report. Additional copies are available without charge upon request by writing to: Investor Relations, Noble Energy, Inc., 1001 Noble Energy Way, Houston, Texas 77070; via the company's website: www.nobleenergyinc.com; or via the SEC's website: www.sec.gov.

Forward-Looking Statements
This 2013 Annual Report to Stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 1A. Risk Factors. Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The SEC permits the optional disclosure of probable and possible reserves; however, we have not disclosed our probable and possible reserves in our filings with the SEC. We use certain terms in this publication, such as "net unrisked resources," "net exploration resources," "risked resources" and "discovered resources," that the SEC's guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosures and risk factors in our Form 10-K included in this report.

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Communications and Media Relations
Ben Dillon
Vice President, Communications and Government Relations
281.872.3100
media@nobleenergyinc.com

Independent Public Accountants
KPMG LLP

Transfer Agent and Registrar
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
800.468.9716
www.shareowneronline.com

Common Stock Listed
New York Stock Exchange
Symbol – NBL

noble energy

www.nobleenergyinc.com

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2013
or
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to
Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

(281) 872-3100
(Registrant's telephone number, including area code)
Securities registered pursuant to section 12(b) of the Act:

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

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

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

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

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(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).☐ Yes ☒ No

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2013: $21.5 billion.

Number of shares of Common Stock outstanding as of December 31, 2013: 359,905,771.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2014 Annual Meeting of Stockholders to be held on April 22, 2014, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2013, are incorporated by reference into Part III.

TABLE OF CONTENTS

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 oil and gas 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 and natural gas exploration and production while embracing our responsibility 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 natural gas liquids (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 substantial 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 2013, we spent over $3 billion in oil and gas exploration and development activities in the US, and approximately $1 billion in international locations.

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 the pursuit of material exploration opportunities which can be monetized on a competitive discovery-to-production cycle through effective major development project execution. During 2013, two major offshore development projects, Tamar, offshore Israel, and Alen, offshore Equatorial Guinea, began production. Our ability to deliver major development projects on schedule and within budget has provided a competitive and financial advantage in the industry.

Onshore US assets provide a stable base of production along with high return, low risk development programs that deliver growth and accommodate flexible capital spending 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
- offshore Eastern Mediterranean.

These five core areas provide:

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

Our growth is supported by a strong balance sheet and liquidity levels. We strive to deliver competitive returns and a growing dividend. Our annual cash dividends have increased 67% in the last five years, from 33 cents per share in 2008 to 55 cents per share in 2013 (as adjusted for the 2-for-1 stock split during the second quarter of 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 2009-2013.

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 2013. 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

- Horizontal Niobrara (onshore US) [(2)]
- Marcellus Shale (onshore US) [(2)]
- Gunflint (deepwater Gulf of Mexico)
- Big Bend (deepwater Gulf of Mexico)
- Tamar Expansion (offshore Israel)
- Tamar Southwest (offshore Israel)

Unsanctioned Projects

- Leviathan (offshore Israel)
- Cyprus (offshore Cyprus)
- Diega and Carla (offshore Equatorial Guinea)
- Dantzler (deepwater Gulf of Mexico)

(1) Final investment decision has been made.

(2) Represents multiple ongoing development projects. The Keota plant and East Pony Integrated Development Plan (IDP) in the Horizontal Niobrara were sanctioned during 2013. We are currently evaluating additional onshore US IDPs for future sanction.

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

Proved Oil and Gas Reserves Proved reserves at December 31, 2013 were as follows:

Summary of 2013 Oil and Gas Reserves as of Fiscal-Year End
Based on Average 2013 Fiscal-Year Prices

	December 31, 2013		
	Proved Reserves		
	Crude Oil, Condensate & NGLs	Natural Gas	Total
Reserves Category	(MMBbls)	(Bcf)	(MMBoe) [(1)]
Proved Developed			
United States	147	1,212	349
Equatorial Guinea	75	457	151
Israel	3	2,046	344
Other International [(2)]	5	2	5
Total Proved Developed Reserves	230	3,717	849
Proved Undeveloped			
United States	185	1,444	425
Equatorial Guinea	19	234	58
Israel	—	433	72
Other International [(2)]	2	—	2
Total Proved Undeveloped Reserves	206	2,111	557
Total Proved Reserves	436	5,828	1,406

(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.

(2) Other international includes the North Sea and China.

Total proved reserves as of December 31, 2013 were approximately 1,406 MMBoe, a 19% increase from 2012. Our proved reserves are 55% US and 45% international. The proved reserves mix is 31% global liquids (crude oil and NGLs), 38% international natural gas, and 31% 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, and 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 numerous 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 2013, we advanced our exploration activities in the following new venture areas: onshore US in northeast Nevada, offshore Falkland Islands, offshore Nicaragua, and offshore Sierra Leone.

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 growing inventory of major development projects. In 2013, we commenced natural gas production from the Tamar field, offshore Israel, followed by the start up of Alen, a natural gas and condensate field, offshore Equatorial Guinea. Additionally, 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.

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 high-value and high-growth areas. The program has generated combined net proceeds of approximately $1.4 billion during the last two years, including $206 million during 2013. 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 2013, we sold onshore US crude oil and natural gas properties located in Kansas, Oklahoma, the Gulf Coast, New Mexico and Wyoming, and non-operated working interests in the North Sea.

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. Acquisitions and Divestitures.

Asset Impairments During 2013, we recorded impairment charges of $86 million primarily related to our Mari-B field, offshore Israel, due to natural field decline, and certain non-core onshore US properties divested during the year or held for sale at December 31, 2013. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

United States

We have been engaged in crude oil and natural gas exploration and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 58% of 2013 total consolidated sales volumes and 55% of total proved reserves at December 31, 2013. Approximately 57% of the proved reserves are natural gas and 43% are crude oil, condensate and NGLs.

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

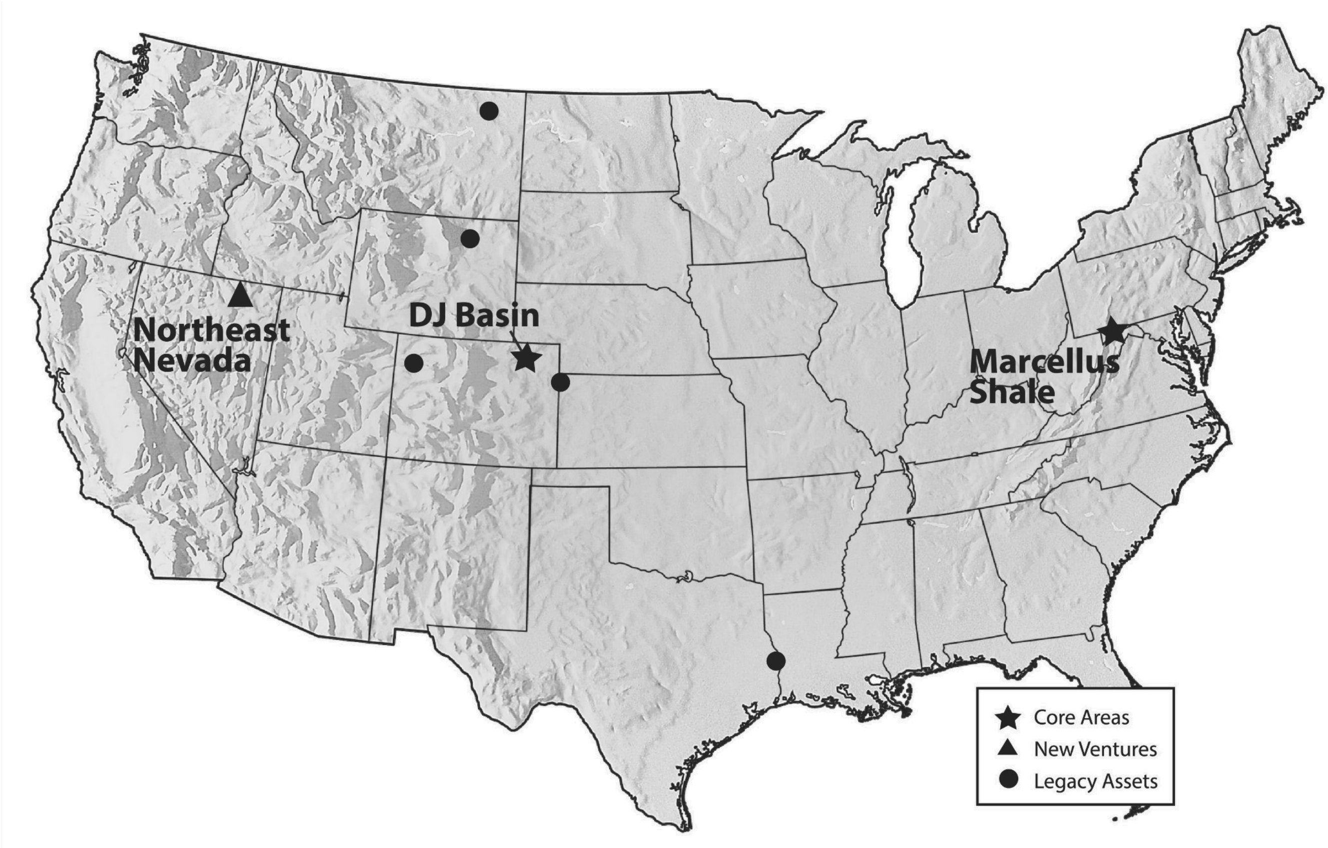
	Year Ended December 31, 2013				December 31, 2013			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
DJ Basin	46	209	14	95	206	1,044	72	450
Marcellus Shale	—	139	1	24	1	1,374	22	252
Deepwater Gulf of Mexico	16	13	1	19	28	33	1	35
Other Onshore US	1	79	—	15	2	205	—	37
Total	63	440	16	153	237	2,656	95	774

Wells drilled in 2013 and productive wells at December 31, 2013 for our US operating areas were as follows:

	Year Ended December 31, 2013	December 31, 2013
	Gross Wells Drilled or Participated in [(1)]	Gross Productive Wells
DJ Basin	470	8,383
Marcellus Shale	117	284
Deepwater Gulf of Mexico	2	13
Other Onshore US	23	3,632
Total	612	12,312

(1) Excludes exploratory wells drilled and suspended awaiting a sanctioned development plan or being evaluated to assess the economic viability of the well. See Drilling Activity, below.

Locations of our onshore US operations as of December 31, 2013 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. It is our largest onshore US field (approximately 730,000 net acres), split between approximately 609,000 net acres in Colorado (approximately 96% operated working interest) and approximately 121,000 net acres in Wyoming (the majority non-operated). We have an extensive inventory of development drilling opportunities and plan to invest approximately 40% of our 2014 capital investment program in the DJ Basin.

The DJ Basin contributed an average of 95 MBoe/d of sales volumes, representing approximately 36% of total consolidated sales volumes in 2013, with approximately 63% being crude oil and NGLs, and represented approximately 32% of total proved reserves at December 31, 2013.

DJ Basin Acreage Exchange In October 2013, we closed an acreage exchange agreement with another operator related to our position in the DJ Basin. We exchanged approximately 50,000 net acres which consolidates our acreage position providing the opportunity to optimize drilling, production, and gathering activities and increase the number of extended-reach lateral wells in our development program. A short-term reduction in production of approximately 8 MBoe/d for fourth quarter 2013 related to the acreage exchange is anticipated to be quickly offset with operational efficiencies and cost savings. 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. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

2013 Activity Over the past year, we have focused our drilling and development activity on Integrated Development Plan (IDP) areas. This approach allows us to consolidate processing and handling infrastructure across large areas (typically 30,000 to 60,000 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 and operations by reducing our land surface and water usage while enabling us to efficiently gather and process crude oil, natural gas, and water from a large surrounding area, and reducing truck traffic and our overall surface footprint. We sanctioned the Wells Ranch IDP in 2012, and brought online our first CPF at Wells Ranch during the fourth quarter of 2013. In 2013, we sanctioned the East Pony IDP in northern Colorado and expect to sanction additional IDPs over the next several years. In the second half of 2014, we will begin operation of the Keota plant, our second natural gas processing plant in northern Colorado, to support our East Pony IDP along with future IDPs in the area. This will enhance our ability to continue development in this part of the Basin.

Also during 2013, we spud a total of 295 development wells, of which 291 were horizontal wells in the Niobrara and Codell formations. We continue to evaluate impacts of changes in well spacing and pad design. The well numbers above include 34 extended-reach (over 5,000 feet) lateral wells. We also participated in approximately 170 non-operated development wells during 2013.

In conjunction with our IDP approach, infrastructure in the area continues to be built out. Several infrastructure projects will come online over the next year and will significantly improve our flow assurance and reduce truck traffic. In the fourth quarter of 2013, a new crude oil gathering pipeline began operations. The new pipeline allows us to move crude oil from the northern parts of the field to several oil processing facilities and transportation hubs, with additional access to end markets. Additionally, a new rail facility commenced operations during the fourth quarter of 2013 to further enhance the transportation of our crude oil out of the field.

Our 2013 DJ Basin development program resulted in additions to proved reserves of approximately 153 MMBoe, approximately 67% 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, including approximately 90,000 gross acres recently acquired to expand our acreage position in northwest West Virginia to further optimize the value of our existing acreage position. We operate the wet gas (natural gas containing more liquid hydrocarbons) development area while CONSOL operates the dry gas (natural gas containing less liquid hydrocarbons) development area.

The Marcellus Shale contributed an average of 139 MMcfe/d of sales volumes and represented approximately 9% of total consolidated sales volumes in 2013 and approximately 18% of total proved reserves at December 31, 2013.

During 2013, we and CONSOL drilled 71 wet gas wells and 46 dry gas wells and brought online 35 wet gas wells and 18 dry gas wells.

Utilizing an IDP concept, modeled after the DJ Basin, we have begun to realize cost efficiencies through longer lateral wells and increased production growth through applied learning, completion design and optimized well placement. The current identified IDP areas are Majorsville, Southwest Pennsylvania Area Dry, and Allegheny County Airport.

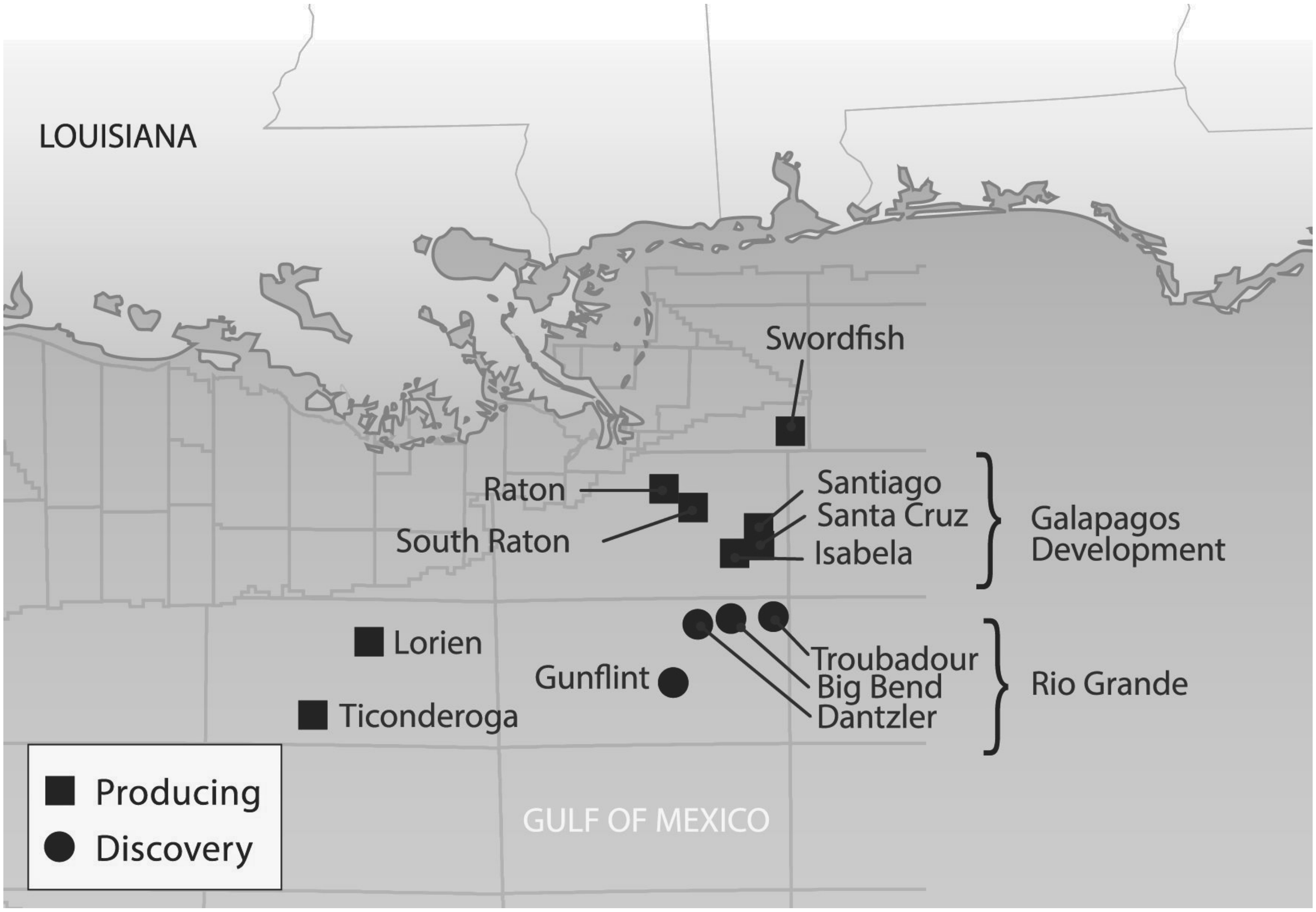
Majorsville is the first operated IDP area, which came online in 2013 and will be the IDP model for the Marcellus Shale. It is in the core operating area with water and marketing infrastructure in place to support further development.

Based on our 2014 joint development plan, we expect to invest approximately 20% of our 2014 capital investment program in the Marcellus Shale.

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. Based on acquired 3D seismic data over portions of the acreage, we began our exploratory drilling program with two exploratory wells drilled in 2013. We are currently evaluating the drilling results.

Other Non-Core Onshore Properties We also operate in the following onshore US areas: Rocky Mountains including Piceance Basin (western Colorado), Bowdoin field (north central Montana), Tri-State field (northeastern Colorado, northwestern Kansas and southwestern Nebraska) and Powder River Basin (north/central Wyoming); and Gulf Coast including the Haynesville field (East Texas and North Louisiana), Comanche Plains field (West Texas). Other non-core onshore properties accounted for 6% of total consolidated sales volumes in 2013 and 3% of total proved reserves at December 31, 2013. During 2013, we sold various non-core onshore properties and continue to evaluate the divestment opportunities associated with other non-core properties. See Acquisition and Divestiture Activities – *Non-Core Divestiture Program* above.

Deepwater Gulf of Mexico Locations of our operations in the deepwater Gulf of Mexico as of December 31, 2013 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 six producing fields, multiple ongoing development projects and a substantial inventory of exploration opportunities.

The deepwater Gulf of Mexico accounted for 7% of total consolidated sales volumes in 2013 and 2% of total proved reserves at December 31, 2013.

We currently hold leases on 121 deepwater Gulf of Mexico blocks, representing approximately 52,000 net developed acres and approximately 409,000 net undeveloped acres. We are the operator on approximately 68% of our leases. See also Developed and Undeveloped Acreage – *Future Acreage Expirations*, below. During 2013, we sanctioned two major development projects in the deepwater Gulf of Mexico, Gunflint and Big Bend. See details below.

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 20 identified prospects, which are a combination of both high impact subsalt prospects and smaller, high value tie-back opportunities. The prospects are subject to an ongoing technical maturation process and may or may not emerge as drillable options. To support the future exploration, appraisal, and development work, we have the ENSCO 8501 rig under contract through the third quarter of 2014. The Atwood *Advantage* drillship is currently mobilizing to the Gulf of Mexico. It will be used in the 2014 drilling plan which includes various exploration, appraisal and well completion activities.

Our most significant deepwater Gulf of Mexico properties and current development plans are discussed in more detail below.

Rio Grande (Mississippi Canyon Block 698, 699, 738 and 782) The Rio Grande area is a co-development opportunity for recent 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. In October 2013, we sanctioned the development plan for Big Bend utilizing a subsea tieback to a third party host facility, with first production targeted for late 2015. We are currently evaluating possible integration of the Dantzler, potentially a 2014 sanctioned project, and Troubadour discoveries into our Rio Grande development plans.

Gunflint (Mississippi Canyon Block 948; 26% operated working interest) Gunflint is a 2008 crude oil discovery. During 2013, we completed drilling our second appraisal well and sanctioned the development plan for Gunflint utilizing a subsea tieback to an existing host facility. First production from Gunflint is targeted for 2016.

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.

Other Offshore Properties

Raton (Mississippi Canyon Block 248; 67% operated working interest) is a 2006 natural gas discovery and has been producing since 2008. South Raton (Mississippi Canyon Block 292; 79% operated working interest) is a 2008 crude oil discovery and began producing in 2012. Both Raton and South Raton are currently shut-in due to mechanical issues. We are currently awaiting access to the third party processing platform to begin remediation efforts on the South Raton well.

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 recently acquired the Neptune Spar, a floating offshore production platform, which will 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, including one drilled in 2013.

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.

Other offshore properties are connected to existing infrastructure through subsea tiebacks.

International

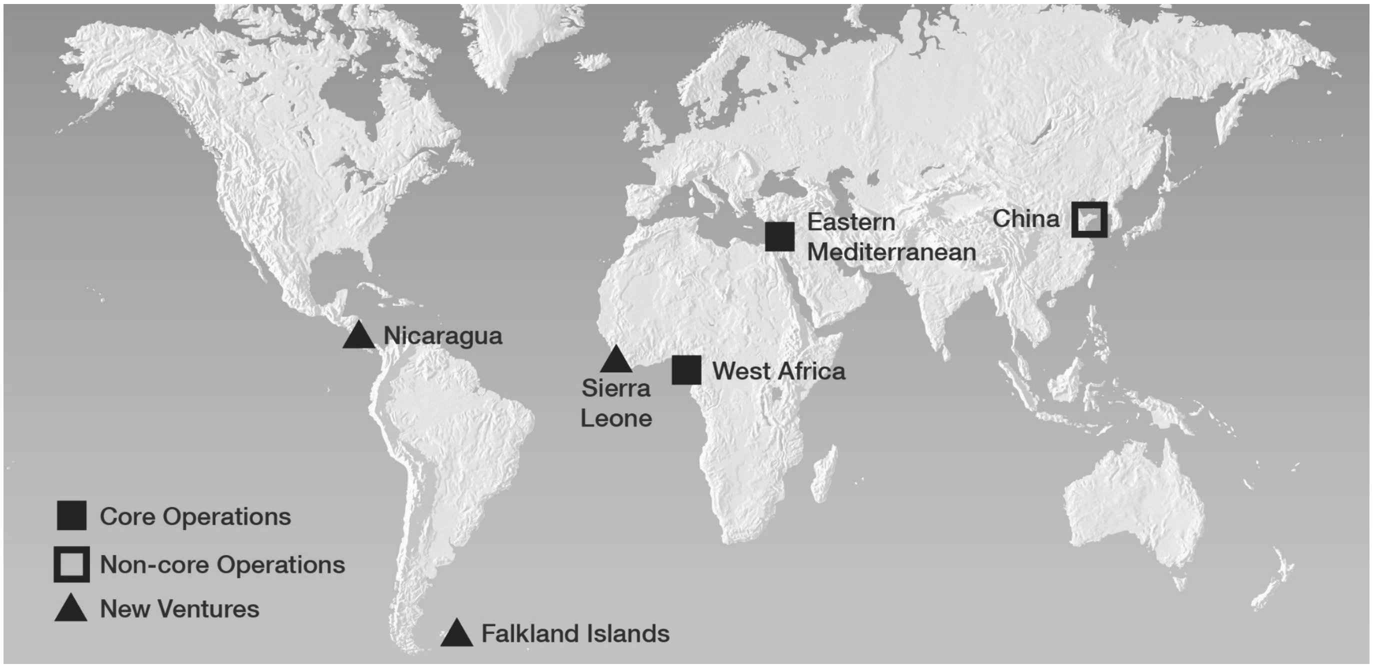
Our international business focuses on offshore opportunities in a number of countries and provides diversity to our portfolio. Development projects in Equatorial Guinea and Israel have contributed substantially to our growth over the last decade.

During 2013, we successfully brought the Tamar project, offshore Israel, and Alen project, offshore Equatorial Guinea, to production as we continue to advance our major development projects. Additionally, significant exploration successes offshore West Africa, Israel and Cyprus have identified multiple major development projects that are expected to contribute to production growth in the future. We expect these large acreage positions in West Africa and the Eastern Mediterranean will provide further exploration opportunities.

International operations accounted for 42% of total consolidated sales volumes in 2013 and 45% of total proved reserves at December 31, 2013. International proved reserves are approximately 84% natural gas and 16% crude oil and condensate. Based on our current 2014 capital investment program, we expect to invest approximately 20% of our 2014 capital investment program in international locations.

Operations in China, Cyprus, Equatorial Guinea, and Sierra Leone are conducted in accordance with the terms of production sharing contracts (PSCs). In Cameroon, we operate in accordance with the terms of a PSC and a mining concession. Operations in Israel, Nicaragua, the Falkland Islands, the North Sea, 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, 2013 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, 2013				December 31, 2013		
	Sales Volumes				Proved Reserves		
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil, Condensate & NGLs	Natural Gas	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBoe)
International							
Equatorial Guinea	32	252	—	73	94	691	209
Israel	—	209	—	35	3	2,479	416
China	4	—	—	4	6	2	6
Total International	36	461	—	112	103	3,172	631
Equity Investee	2	—	6	8	—	—	—
Discontinued Operations (North Sea)	1	2	—	1	1	—	1
Total	39	463	6	121	104	3,172	632
Equity Investee Share of Methanol Sales (MMgal)				155			

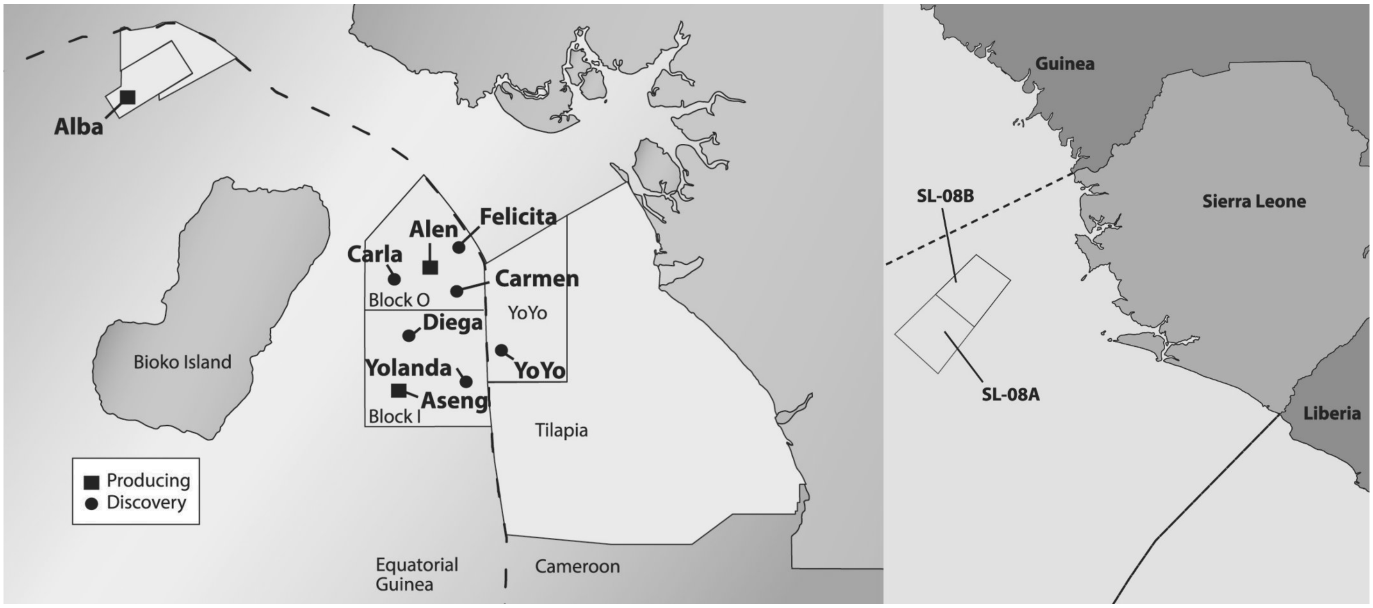
Wells drilled in 2013 and productive wells at December 31, 2013 in our international operating areas were as follows:

	Year Ended December 31, 2013	December 31, 2013
	Gross Wells Drilled or Participated in [(1)]	Gross Productive Wells
International		
Equatorial Guinea	—	24
Israel	—	7
North Sea	—	6
China	3	30
Nicaragua	1	—
Total International	4	67

(1) Excludes exploratory wells drilled and suspended awaiting a sanctioned development plan or being evaluated to assess the economic viability of the well. See Drilling Activity, below.

West Africa (Equatorial Guinea, Cameroon and Sierra Leone) West Africa is one of our core operating areas and includes the Alba field, Block O and Block I offshore Equatorial Guinea, as well as the YoYo mining concession and Tilapia PSC, offshore Cameroon, and two blocks offshore Sierra Leone. Equatorial Guinea, the only producing country in our West Africa segment, accounted for approximately 28% of 2013 total consolidated sales volumes and 15% of total proved reserves at December 31, 2013. We held approximately 118,000 net developed acres and 80,000 net undeveloped acres in Equatorial Guinea, 695,000 net undeveloped acres in Cameroon, and 414,000 net undeveloped acres in Sierra Leone at December 31, 2013.

Locations of our operations in West Africa as of December 31, 2013 are shown on the map below:



Alen Project Alen, our second major operated development project in West Africa, is a natural gas and condensate field primarily on Block O (45% operated working interest), offshore Equatorial Guinea. Alen began production in the second half of 2013, ahead of the original target start up date, and utilizes the Aseng FPSO for storage and offloading. Alen exited 2013 with production of 28 MBbl/d, and peak production of 30 to 35 MBbl/d is expected in 2014.

Aseng Project Aseng is a crude oil field on Block I (40% operated working interest), offshore Equatorial Guinea, which includes five horizontal wells flowing to the Aseng FPSO. Aseng started production in late 2011. The oil is stored on the Aseng FPSO until sold, while the natural gas and water are reinjected into the reservoir to maintain pressure and maximize oil recoveries.

The Aseng FPSO is designed to act as an 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. It is capable of processing 120 MBbl/d of liquids, including 80 MBbl/d of oil, and reinjection of up to 160 MMcf/d of natural gas. The Aseng FPSO has storage capacity of approximately 1.6 MMBbls of liquids. During 2013, Aseng maintained reliable and safe performance and averaged almost 99% production uptime.

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.

We sell our share of natural gas production from the Alba field to the LPG plant, the methanol plant and an unaffiliated LNG plant. The LPG plant is owned by Alba Plant LLC (Alba Plant), in which we have a 28% interest accounted for as an equity method investment. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest, also accounted for as an equity method investment. AMPCO purchases natural gas from the Alba field under a contract that runs through 2026 and subsequently markets the produced methanol primarily to customers in the US and Europe. Alba Plant sells its LPG products and 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 with an anticipated completion date in 2016.

Other Block O & I Projects We are continuing our exploration and appraisal efforts offshore Equatorial Guinea. During the second half of 2013, we successfully drilled the Diega I-8 appraisal well, and we are targeting to sanction a development project in 2014, with first production targeted for 2016.

We continue to review the drilling results of the Carla O-7 and the Carla I-7 wells and evaluate regional development scenarios for the Carla discovery.

West Africa Gas Project We have a natural gas development team working with Equatorial Guinea's Ministry of Mines, Industry and Energy to evaluate several monetization options for natural gas in the region.

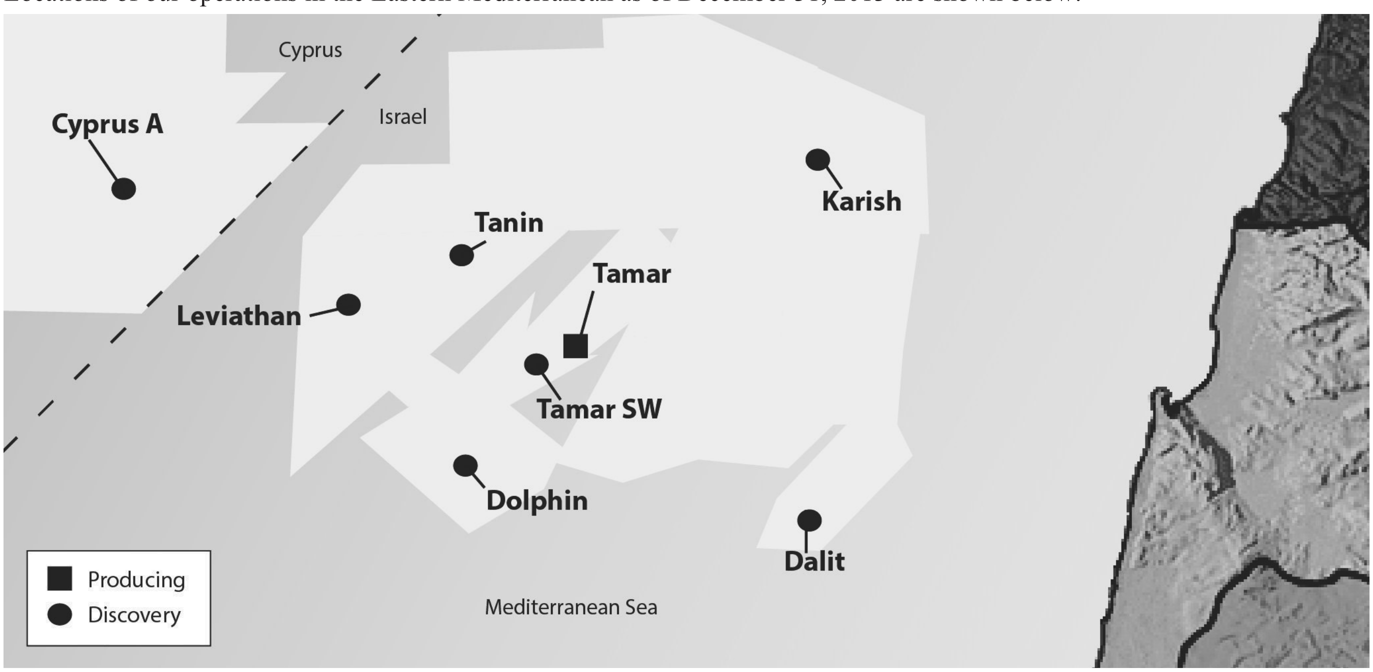
Cameroon We have an interest in over one million gross undeveloped acres offshore Cameroon, which include the YoYo mining concession (50% operating working interest) and Tilapia PSC (66.67% operating working interest). The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options.

Sierra Leone We participate in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million gross undeveloped acres. Under the terms of the award, Chevron (SL) Ltd. is the operator and we have a non-operated 30% working interest. During 2013, we acquired and began processing 766 square miles of 2D seismic information over portions of the acreage to assist with our 3D seismic plans.

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. We plan to explore for additional natural gas prospects as well as for crude oil, which may exist at greater depths in the basin.

Israel, the only producing country in our Eastern Mediterranean core area, accounted for 13% of 2013 total consolidated sales volumes and 30% of total proved reserves at December 31, 2013. Our leasehold position in the Eastern Mediterranean includes four leases and seven licenses offshore Israel and one license offshore Cyprus, and we are the operator of the properties at December 31, 2013. We held approximately 80,000 net developed acres and 326,000 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 596,000 net undeveloped acres adjacent to our Israel acreage.

Locations of our operations in the Eastern Mediterranean as of December 31, 2013 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 as a fuel in the future.

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, and, as discussed further below, we are considering multiple development options. The government of Israel recently finalized an export policy. See Regulations – *Update on Israel's Natural Gas Policy*, below.

Tamar Natural Gas Project Just over four years from discovery, the Tamar project began production in March 2013 and is now fully operational and delivering significant volumes of natural gas to Israel. 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 Ashdod onshore terminal (AOT). Tamar is a technical and commercial milestone that significantly contributes to our production growth. Production from Tamar averaged 153 MMcf/d, net, for the year with capable peak flow rates of approximately 1.0 Bcf/d gross to support seasonal high demand periods.

During 2013, we sanctioned the Tamar expansion project, which is estimated to grow our AOT capacity by 200 MMcf/d with operational start-up in the second half of 2015. Additionally, we are targeting the Tamar facility for further expansion up to 1.5 Bcf/d of capacity in 2016.

The Tamar partners have executed numerous gas sale and purchase agreements (GSPAs) for the initial and expanded capacity. See International Marketing Activities and Delivery Commitments, below.

Tamar Southwest During the second half of 2013, we drilled the successful Tamar Southwest natural gas exploratory well. Tamar Southwest, which was drilled to a total depth of 17,420 feet in 5,405 feet of water, is our eighth consecutive discovery in the Levant Basin. The field is located approximately eight miles southwest of the Tamar field. We operate Tamar Southwest with a 36% working interest, and we anticipate first production in 2015 utilizing Tamar infrastructure as part of our expansion project to meet domestic demand. Tamar Southwest will also provide flow rate assurance for our overall Tamar project.

Leviathan Natural Gas Project In December 2010, we announced a significant natural gas discovery at the Leviathan-1 well offshore Israel in the Levant Basin. The Leviathan field is the largest discovery in our history and was the world's largest offshore natural gas discovery in 2010. We own a 39.66% working interest in Leviathan. In 2013, the successful results from our recent Leviathan-4 appraisal well enhanced our understanding of the reservoir, and we continue our evaluation of multiple development concepts. Due to Leviathan's size, full field development is expected to require several development phases.

The Leviathan Phase 1 development concept is likely to serve both domestic demand and export. Domestic production could begin as early as 2017. We and our Leviathan partners recently signed a GSPA to sell approximately 170 Bcf of natural gas over a 20-year period to the Palestine Power Generation Company (PPGC). PPGC plans to build a power plant in the West Bank.

Multiple export options, including pipeline, onshore LNG, and floating LNG are under evaluation. Timing of project sanction depends on execution of natural gas sales contracts, determination of an onshore entry point and government approvals.

Woodside Agreement We and our Leviathan partners continue working with Woodside Energy Ltd. (Woodside) to reach a definitive agreement to sell portions of our working interests in the Leviathan licenses to Woodside. Such an agreement would be subject to customary government approvals. Noble expects to convey a 9.66% working interest, reducing our working interest in the Leviathan licenses to 30%. Noble would continue as upstream operator.

Cyprus During the second half of 2013, we drilled the successful Cyprus A-2 appraisal well on Block 12, offshore Cyprus. The A-2 well was drilled to a total depth of 18,865 feet in 5,575 feet of water and encountered approximately 120 feet of net natural gas pay within the targeted Miocene-aged sand intervals. We anticipate additional appraisal activities to further refine the ultimate recoverable resources and optimize field development planning. In addition to the appraisal well, we completed the acquisition phase of a 3D seismic study and are currently processing the results. We are the operator on Block 12 and hold a 70% working interest.

Leviathan-1 Deep (Mesozoic Oil Target) In January 2012, we returned to the Leviathan-1 well and began drilling toward two deeper intervals in order to evaluate them for the existence of crude oil (Leviathan-1 Deep). In May 2012, due to high pressures and the mechanical limits of the wellbore design, we suspended drilling operations. Although the well did not reach the planned objective, we are encouraged by the possibility of an active thermogenic (crude oil generating) hydrocarbon system at greater depths within the basin. We have integrated the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically for a potential test of the deep oil concept.

Mari-B, Pinnacles and Noa Fields The Mari-B field (47% operated working interest) was the first offshore natural gas production facility in Israel and has been producing since 2004. In order to help meet Israeli natural gas demand prior to the commencement of Tamar production, we completed the Noa (47% operated working interest) and Pinnacles (47% operated working interest) wells and tied them back to the Mari-B platform in 2012. During 2013, we ramped down production from these fields when Tamar commenced production.

Other Discoveries Offshore Israel We and our partners are working on a development plan for the Dalit field (36% operated working interest), a 2009 natural gas discovery. Development would include tie-in to the Tamar platform, and we have submitted a development plan to the Israeli government. In addition, we are reviewing alternatives for the development of the Karish (47.06% operated working interest), Dolphin (39.66% operated working interest) and Tanin 1 (47.06% operated working interest) natural gas discoveries. See Regulations – *Update on Israel's Natural Gas Economy*.

Other International

Our other international operations accounted for 1% of our total consolidated sales volumes for 2013 and less than 1% of total proved reserves at December 31, 2013.

Falkland Islands In August 2012, we entered into an agreement with Falkland Oil and Gas Limited (FOGL) to acquire an interest in FOGL's extensive license areas, consisting of approximately 10 million gross acres located south and east of the Falkland Islands. Under the agreement, we have farmed-in to the Northern and Southern Area Licenses for a 35% working interest.

In March 2013, we assumed operatorship of the Northern Area License from FOGL. In January 2014, we assumed operatorship of the Southern Area License, pending governmental approval. We continue to process recently acquired 3D seismic information for the Southern Area License and began acquisition of 3D seismic information for the Northern Area License in late 2013. The construction of our shore base facility is ongoing in preparation for our first operated exploratory well which we expect to drill in 2015.

During fourth quarter 2012, FOGL drilled the Scotia exploratory well, which reached its Cretaceous objective and encountered 40 feet of net pay. Although we did not see a substantial amount of the reservoir section, virtually all sandstones with significant porosity in and below the target area contained hydrocarbons. Integration of well results with the 3D seismic information we are acquiring will allow us to assess the economic viability of this prospect.

Nicaragua During the second half of 2013, we transferred a portion of our working interests in acreage offshore Nicaragua, pending government approval, to two new partners, reducing our working interest to 70%. Additionally, we drilled the Paraiso-1 exploratory well, the first deepwater well drilled offshore Nicaragua. The Paraiso-1 did not encounter commercial quantities of hydrocarbons. However, the information gathered from this well will be integrated into our regional geologic model to help us assess the remaining exploration potential over our nearly two million gross acre position offshore Nicaragua.

China We have been engaged in exploration and development activities in China since 1996 under the terms of a PSC, expiring in 2018. We have a 57% non-operated working interest in the Cheng Dao Xi field, which is located in the shallow water of the southern Bohai Bay.

We are currently negotiating for the sale of our China properties and expect the transaction to close during the first half of 2014. As of December 31, 2013, our China properties are included in assets held for sale in our consolidated balance sheet.

North Sea During 2013, we sold substantially all of the non-operated working interest properties located in the UK and Netherlands sectors of the North Sea. On a combined basis, the sales resulted in a $65 million gain based on net sales proceeds of $56 million for the fields, and we continue to market our remaining North Sea properties. The North Sea's fourth quarter production was 600 Boe/d.

As of December 31, 2013, all the properties remaining in our North Sea geographical segment are included in assets held for sale in our consolidated balance sheet. Our consolidated statements of operations have been reclassified for all periods presented to reflect the operations of our North Sea geographical segment as discontinued.

See Item 8. Financial Statements and Supplementary Financial Data – Note 3. Property Transactions.

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 members of senior management.

Our Senior Vice President – Corporate Development oversees our corporate business development, new ventures, strategic planning, environmental analysis and reserves departments. He is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has Bachelor of Science and Master of Science degrees in Petroleum Engineering and over 33 years of industry experience with positions of increasing responsibility in engineering, evaluations, and business unit management at the Company. The Senior Vice President – Corporate Development reports directly to our Chief Executive Officer.

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

We used a combination of production and pressure performance, wireline wellbore measurements, simulation studies, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs and core data to calculate our reserves estimates, including the material additions to the 2013 reserves estimates.

Third-Party Reserves Audit In each of the years 2013, 2012, and 2011, we retained NSAI to perform reserves audits of proved reserves. The reserves audit for 2013 included a detailed review of nine of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 74% of US proved reserves and 98% of international proved reserves (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. The reserves audit for 2011 included a detailed review of 14 of our major fields and covered approximately 90% of total proved reserves.

In connection with the 2013 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, oil and 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, 2013, 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, 2013, on a quantity basis, the NSAI field estimates ranged from 21 MMBoe or 8% above to 15 MMBoe or 5% 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, 2013 were, in the aggregate, approximately 9 MMBoe, or 1%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2013, our PUDs totaled 206 MMBbls of crude oil, condensate and NGLs and 2.1 Tcf of natural gas, for a total of 557 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, 2013:

- 227 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 over an approximate three-year period;
- 177 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 over an approximate two-year period;
- 20 MMBoe in the deepwater Gulf of Mexico;
- 58 MMBoe in the Alba field, offshore Equatorial Guinea, 55 MMBoe of which have been recorded as PUDs for over five years and are attributable to a sanctioned compression project, for which construction has commenced. These volumes, which will be recovered through existing wells, will be reclassified to proved developed at start-up, currently expected in 2016; and
- 72 MMBoe in Israel primarily in the Tamar and Tamar Southwest fields.

The above fields represent 99% of total PUDs. The remaining 1% is associated with ongoing developments in various areas scheduled to be drilled in the next five years. 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:

	United States	Equatorial Guinea	Israel	China	Total
(MMBoe)					
Proved Undeveloped Reserves Beginning of Year	272	74	375	2	723
Revisions of Previous Estimates	41	8	2	(1)	50
Extensions, Discoveries and Other Additions	153	3	30	1	187
Purchase of Minerals in Place	22	—	—	—	22
Conversion to Proved Developed	(63)	(27)	(335)	—	(425)
Proved Undeveloped Reserves End of Year	425	58	72	2	557

United States

- positive revisions of 39 MMBoe, primarily due to increased recovery assumptions in the DJ Basin and Marcellus Shale as a result of better than expected performance from existing wells;
- positive revisions of 2 MMBoe, primarily in the Marcellus Shale, due to changes in commodity prices;
- additions of 81 MMBoe in the DJ Basin horizontal drilling program;
- additions of 58 MMBoe in the Marcellus Shale horizontal drilling program;
- additions of 14 MMBoe in the deepwater Gulf of Mexico due to recently sanctioned Gunflint and Big Bend projects;
- purchases of 22 MMBoe related to acquisitions of additional Marcellus Shale acreage; and
- conversion of 63 MMBoe into proved developed reserves attributable to ongoing development in the DJ Basin (19% of year end 2012 PUD volumes converted) and Marcellus Shale (30% of year end 2012 PUD volumes converted).

Equatorial Guinea

- positive revisions of 8 MMBoe due to performance revisions for the Alba field;
- additions of 3 MMBoe attributable to an infill location at the Alba field; and
- conversion of 27 MMBoe due to start-up of the Alen field.

Israel

- positive revisions of 2 MMBoe due to performance revisions for the Tamar field;
- additions of 30 MMBoe in the recently discovered and sanctioned Tamar Southwest field; and
- conversion of 335 MMBoe due to start-up of the Tamar field.

Development Costs Costs incurred to advance the development of PUDs were approximately $1.0 billion in 2013, $1.8 billion in 2012, and $1.4 billion in 2011. A significant portion of costs incurred in 2013 related to the following development projects: horizontal Niobrara; Marcellus Shale; Alen; and Tamar, which were converted to proved developed reserves in 2013.

Estimated future development costs relating to the development of PUDs are projected to be approximately $3.2 billion in 2014, $2.1 billion in 2015, and $1.2 billion in 2016. 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 2018. PUDs associated with our Alba compression project are also expected to be converted to proved developed reserves prior to the end of 2018. Initial production from these PUDs is expected to begin during the years 2014 - 2018.

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 and natural gas 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, 2013, 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.

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/d	Natural Gas MMcf/d	NGLs MBbl/d	Crude Oil & Condensate Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per BOE
Year Ended December 31, 2013							
United States							
DJ Basin	46	209	14	$ 93.28	$ 3.50	$ 36.33	$ 4.71
Marcellus Shale	—	139	1	79.62	3.67	30.92	2.80
Other US	17	92	1	105.56	3.44	31.73	13.99
Total US	63	440	16	96.53	3.54	35.53	6.47
Equatorial Guinea	32	252	—	107.48	0.27	—	3.96
Israel							
Tamar Field	—	153	—	—	5.32	—	2.61
Other Israel	—	56	—	—	4.22	—	6.79
Total Israel	—	209	—	—	5.02	—	3.73
China	4	—	—	103.21	—	—	9.45
Total Consolidated Operations	99	901	16	100.29	2.97	35.53	$ 5.46
Equity Investee [3]	2	—	6	105.37		68.12	
Total Continuing Operations	101	901	22	$ 100.38	$ 2.97	$ 43.90	
Year Ended December 31, 2012							
United States							
DJ Basin	32	194	13	$ 89.41	$ 2.67	$ 35.50	$ 4.45
Other US	17	244	3	104.30	2.57	34.92	8.00
Total US	49	438	16	94.69	2.61	35.36	6.04
Equatorial Guinea							
Alba Field [2]	12	235	—	107.08	0.27	—	2.79
Aseng Field	21	—	—	111.93	—	—	4.88
Total Equatorial Guinea	33	235	—	110.14	0.27	—	3.39
Mari-B Field (Israel)	—	101	—	—	4.85	—	3.23
China	4	—	—	114.54	—	—	10.33
Total Consolidated Operations	86	774	16	101.52	2.19	35.36	$ 5.09
Equity Investee [3]	2	—	5	104.56	—	69.14	
Total Continuing Operations	88	774	21	$ 101.58	$ 2.19	$ 44.15	
Year Ended December 31, 2011							
United States							
DJ Basin	23	166	11	$ 90.05	$ 3.95	$ 49.45	$ 4.58
Other US	15	222	4	103.30	3.87	45.40	7.45
Total US	38	388	15	95.19	3.90	48.35	6.24
Equatorial Guinea							
Alba Field [2]	12	245	—	107.70	0.27	—	2.35
Aseng Field	2	—	—	106.87	—	—	9.08
Total Equatorial Guinea	14	245	—	107.57	0.27	—	2.64
Mari-B Field (Israel)	—	173	—	—	4.86	—	1.16
China	4	—	—	106.19	—	—	9.61
Total Consolidated Operations	56	806	15	99.17	3.00	48.35	$ 4.47
Equity Investee [3]	2	—	5	108.76	—	72.71	
Total Continuing Operations	58	806	20	$ 99.46	$ 3.00	$ 54.84	

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

(2) Natural gas 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, 2013, 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, 2013 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	6,376	5,848.5	5,936	4,647.6	12,312	10,496.1
Equatorial Guinea	5	2.0	19	7.1	24	9.1
Israel	—	—	7	2.7	7	2.7
North Sea	5	0.7	1	0.2	6	0.9
China	29	16.5	1	0.6	30	17.1
Total	6,415	5,867.7	5,964	4,658.2	12,379	10,525.9

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, 2013 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore	1,613	1,074	1,458	933
Offshore	115	52	575	409
Total United States	1,728	1,126	2,033	1,342
International				
Equatorial Guinea	284	118	180	80
Falkland Islands	—	—	9,921	3,472
Cameroon	—	—	1,084	695
Israel	185	80	752	326
Cyprus	—	—	852	596
North Sea	6	1	20	4
China	7	4	—	—
Sierra Leone	—	—	1,380	414
Nicaragua	—	—	1,923	1,346
Total International	482	203	16,112	6,933
Total	2,210	1,329	18,145	8,275

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

A gross acre is any leased acre in which a working interest is owned. A net acre is comprised of the total of the owned working interest(s) in a gross acre expressed in a fractional format.

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

	Year Ended December 31,					
	2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US [1]	321	205	306	153	272	219
Deepwater Gulf of Mexico	20	14	42	40	81	50
Equatorial Guinea	55	19	—	—	—	—
Israel [2]	691	303	—	—	—	—
Cyprus [2]	852	596	—	—	—	—
Cameroon [3]	—	—	458	305	—	—
Total	1,939	1,137	806	498	353	269

(1) Represents acreage that will expire if no further action is taken to extend. Approximately 52% 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 - *Update on Israel Natural Gas Policy*.

(3) The acreage in Cameroon is comprised of our Tilapia PSC and YoYo mining concession. Pursuant to the Tilapia PSC, our second exploration period expires on July 6, 2015; however, we have the right to extend our acreage for an additional two years. Pursuant to our YoYo mining concession, development must commence prior to December 2014, and we are actively engaged in negotiations to extend the term of the mining concession to 35 years.

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, 2013							
United States	5.8	—	5.8	341.7	3.9	345.6	351.4
Equatorial Guinea	—	—	—	—	—	—	—
China	—	—	—	1.7	—	1.7	1.7
Nicaragua	—	0.7	0.7	—	—	—	0.7
Total	5.8	0.7	6.5	343.4	3.9	347.3	353.8
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
Year Ended December 31, 2011							
United States	9.6	3.7	13.3	641.2	4.0	645.2	658.5
Equatorial Guinea	—	—	—	0.5	—	0.5	0.5
Cameroon	—	0.5	0.5	—	—	—	0.5
Senegal/Guinea-Bissau	—	0.3	0.3	—	—	—	0.3
China	—	—	—	2.9	—	2.9	2.9
Total	9.6	4.5	14.1	644.6	4.0	648.6	662.7

In addition to the wells drilled and completed in 2013 included in the table above, wells that were in the process of drilling or completing at December 31, 2013 were as follows:

	Exploratory [1]		Development[2]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	10	5.6	188	106.8	198	112.4
Cameroon	1	0.5	—	—	1	0.5
Cyprus	2	1.4	—	—	2	1.4
Equatorial Guinea	9	4.2	—	—	9	4.2
Falkland Islands	1	0.4	—	—	1	0.4
Israel	8	3.3			8	3.3
Total	31	15.4	188	106.8	219	122.2

(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.

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

Oil Spill Response Preparedness In the US, we maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. On behalf of its membership, CGA 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, can 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.

In May 2013, we successfully led a full-scale drill deployment of critical well control equipment to assess our ability to respond to a potential subsea blowout in the deepwater Gulf of Mexico. The drill was a collaborative test between the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE), the US Coast Guard, Louisiana Offshore Coordinator's Office and all 15 member companies of the HWCG consortium. Activation of the HFRS rapid response system and deployment of the HWCG capping stack to pressurization requirements met all objectives and marked the successful completion of the exercise.

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. We also maintain agreements internationally with Seacor Holdings Inc. (Seacor). Seacor 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.

In June 2013, we conducted a Full Scale Oil Spill Response exercise offshore Israel with participation from Israel’s Ministry of Environmental Protection, Ministry of Energy and Water Resources, Ministry of Transportation, and Ministry of Defense. This exercise successfully demonstrated to the Israeli government our ability to deploy and manage resources in an emergency.

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

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 coming online in the near future will improve flow assurance and enhance transportation of produced crude oil and natural gas to end markets.

International Marketing Activities Our share of crude oil and condensate from the Aseng and Alen fields is sold to Glencore Energy UK Ltd (Glencore Energy) under a long-term sales contract through May 2015, at market rates, and is transported by tanker. 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, and is 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, we sell crude oil into the local market through pipelines under a long-term contract through the end of the field's production life at market-based prices.

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

Israel 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 with a 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, 2013, a total of approximately 6.2 Tcf, gross, (2.2 Tcf, net) of natural gas remained to be delivered under the contracts. At December 31, 2013, we have recorded 2.5 Tcf, net, of proved natural gas reserves, including 433 Bcf, net, of PUD reserves, for offshore Israel.

Significant Purchasers Glencore Energy was the largest single non-affiliated purchaser of 2013 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 25% of 2013 total crude oil, natural gas and NGL sales, or 34% of 2013 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 13% of 2013 total crude oil, natural gas and NGL sales, or 17% of crude oil sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2013. 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 Although commodity prices are historically volatile, price changes were relatively mild in 2013. 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, near-term cash flow volatility is reduced, which allows us to plan our financial commitments and support our capital investment programs.

Our practice has been to hedge up to 50% of our forecasted hedgeable crude oil and 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. We exercise strong management of our hedging program with strong oversight by our Board of Directors. For additional information, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Regulations

Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated at the federal, state, and local levels in the US, and internationally. Crude oil and natural gas 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 regulatory requirements on oil and gas companies.

Our ability to economically produce and sell crude oil and natural gas 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 and regulations 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 and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory requirements on the crude oil and natural gas industry often result in incremental costs of doing business and consequently affect our profitability. See Item 1A. Risk Factors.

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 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;
- various agencies in China which, under such laws as the Provisional Regulations on Administration and Management of the Abandonment of Offshore Oil and Gas Producing Facilities enacted in 2010, regulate our development and production activities offshore China;
- 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 other laws affecting our international operations are the Israeli Petroleum Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production, and the UK Finance Bill 2011, which increased the rate of the Supplementary Charge levied on oil and gas income. Under the Israeli Petroleum Profits Taxation Law, 2011, the depletion allowance was abolished, and a levy at an initial rate of 20% was imposed on profits from oil and gas. The levy gradually rises to 50%, depending on the levy coefficient (the R-Factor). The R-Factor refers to the percentage of the amount invested in the exploration, development and establishment of the project, so that the 20% rate is imposed only after a recovery of 150% of the amount invested (R-Factor of 1.5) and scales linearly up to a maximum of 50% after a recovery of 230% of the amount invested (R-Factor of 2.3). The rate of royalties paid to the State of Israel remained unchanged. Also affecting our operations in Israel is the Law for Change in the Tax Burden (Amendments to Legislation), 2011 (the 2011 Tax Act). As from 2012, the 2011 Tax Act eliminated, inter alia, a previously enacted progressive reduction in the corporate tax rate, and increased the corporate tax rate to 25%. The Israeli corporate tax rate was further increased from 25% to 26.5% as a part of the Budget Law 2013-2014, in 2013.

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

- the Bureau of Land Management (BLM), the Bureau of Ocean Energy Management (BOEM) and 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, 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, as amended, the Resource Conservation and Recovery Act, as amended, 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, which under the Endangered Species Act has authority over activities that may result in the take of an endangered 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 and natural gas 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.

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, wetlands, migratory birds, and 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 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 that requires, among other things, a more detailed environmental review prior to leasing oil and natural gas rights, increased public engagement in the development of master leasing and development plans prior to leasing areas 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 greenhouse gas (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 (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 and natural gas 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. During the first phase, until January 2015, owners and operators 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 is already one of our priorities and we have been working to improve our methods to reduce GHGs through operational and business practices. We use green completions or flaring 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.

Most of the states within which we operate have separate agencies with authority to regulate related 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 oil and 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 oil and 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.

On the environmental side, the Colorado Department of Public Health and Environment, under delegation from the EPA, has adopted measures to regulate air emissions, water protection and waste handling and disposal relating to our oil and gas exploration and production. Moreover, the Colorado Department of Public Health and Environment has proposed extending the EPA's air standards for oil and gas operations by directly controlling methane emissions.

In November 2013, the state of Colorado proposed rules to regulate detection and reduction of methane emissions associated with oil and gas drilling. The proposed 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.

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 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 and arguments were presented on October 18, 2012. The Supreme Court upheld the lower court's decision, which could make it more difficult to develop our Marcellus Shale acreage in some municipalities within Pennsylvania.

NETL Study 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 will monitor the results of the NETL study in order to assess any potential impact on our onshore US development programs.

Other Jurisdictions In December 2011, the West Virginia legislature passed, and the governor signed, the Natural Gas Horizontal Wells Control Act, which, among other things, provides for increased well permit fees, well location restrictions, well site safety, public notice requirements for municipalities, and regulations regarding water use and wastewater handling.

Some of the counties and municipalities where we operate have adopted regulations or ordinances that impose additional restrictions on our oil and gas exploration and production. An example is Garfield County, Colorado, which provides local land and road use restrictions affecting our Piceance Basin operations and requires us to post bonds to secure any restoration obligations. Beyond that, in 2012, Longmont, Colorado prohibited the use of hydraulic fracturing. The oil and gas industry is challenging that ban, and the authority of local jurisdictions to regulate oil and gas development, in court. In November 2013, several other Colorado municipalities passed ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries. See Hydraulic Fracturing.

Update on Israel's Natural Gas Policy In 2011, the Interministerial Committee to Examine Government Policy Regarding the Natural Gas Industry in Israel (the Committee) was charged with the task of proposing a government policy for developing the natural gas economy. Objectives include the following:

- ensuring energy security in the economy;
- providing a framework for substantial resource exports;
- designating a certain percentage of production from each field for domestic natural gas demand;
- maintaining competition in the different sectors of the local economy;
- maximizing economic and political benefits; and
- leveraging environmental advantages with respect to the use of natural gas.

The Committee was also asked to examine, among other items, the desired policy to maintain reserves to supply local demand and export of natural gas. In September 2012, the Committee issued its final recommendations. In its report, the Committee stated that permitting export of natural gas does not harm, but rather promotes the needs of domestic users and encourages development of natural gas-based domestic industry. The recommendations included, among others, the following points:

- as a rule, all reservoirs should be charged with supplying a certain percentage of natural gas to the local economy, with minimum requirements based on reservoir size (minimum of 25%-50%). The minimum supply obligations will not apply for reservoirs under a certain size (25 BCM) but the reservoirs will be required to be connected to the domestic market. The recommendations allow for a lease in a developed reservoir to exchange its export quota against an "obligation to supply to the domestic market" which applies to any other leaseholder which submitted a development plan so long as approval therefor is given by the Petroleum Commissioner in the Ministry of Energy and Water Resources and by the Israeli Antitrust Authority;
- a determination that the quantity of natural gas that should be guaranteed in favor of the local economy should be 450 BCM and that the quantity should be updated in five years;
- the export of natural gas should be permitted as long as the quantity from all reservoirs does not exceed 500 BCM, which amount may be reassessed;
- regulatory approval required for export, with export licenses eligible for periods up to 25 years;
- there should be an absolute preference for the export of natural gas from a facility in an area under Israeli control, including Israel's exclusive economic zone, although further study of various export means (such as export from a foreign area governed by bilateral agreement) and statutory feasibility is necessary; and
- 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 a limitation on the exports allowed from the Tamar field (50% of uncontracted quantities). However, certain members of the Knesset, the Israeli parliament, demanded that natural gas policy, including exports, be legislated by the Knesset as opposed to a government decision. The legality of the government decision was appealed to the Israeli High Court of Justice (High Court). The High Court rejected the appeal on October 21, 2013.

Together with the approval of the Committee recommendations on June 23, 2013, the government has required the Ministry of Finance to submit recommendations on export pricing guidelines. The Ministry of Finance has established a work team, which includes representatives from the Tax Authority, the Budgets Department, and the Department of the Chief Economist. The work team was assigned with the aim of presenting a taxation model that will suit all types of export transactions in accordance with the principles detailed in the government resolution. In accordance with a Ministry of Finance notice, we and our partners have submitted several comprehensive responses to the work team and also conducted several follow-up meetings. The work team is expected to publish its recommendations in early 2014.

With our partners, we are continuing to study the official export and natural gas development policies and are monitoring any additional developments 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 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 closing of a farm-out agreement which we and our partners are negotiating with Woodside or preclude such an agreement entirely, and/or render future exploration and development projects uneconomic.

Additionally, the Israeli Antitrust Commissioner (Commissioner) has been actively engaged to encourage competition in developing Israel's natural gas resources. The Commissioner 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 gas customers. In addition, the Commissioner has initiated a hearing process to evaluate a contention that allegedly the original acquisition agreement for the Leviathan acreage is a restrictive arrangement. The Commissioner has publicly expressed concerns regarding ownership concentration in exploration blocks and development projects and its potential impacts on a competitive domestic natural gas market. We continue to engage with the Israeli government on this matter. Antitrust Commissioner decisions and actions could potentially result in a requirement to divest assets, reduce or relinquish revenue interests, and/or implement the marketing of our working interest share of production. We have cooperated with the Antitrust Authority's review and, at this time, cannot predict the outcome.

Impact of Dodd-Frank Act Derivatives Regulation The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, 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. Because the margin regulations for uncleared swaps have not been adopted, it is possible that the CFTC, in conjunction with prudential banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral. If this should occur, we intend to manage our credit relationships to minimize collateral requirements. These requirements may increase the cost to our counterparties of hedging the swap positions they enter into with us, and thus may increase our cost of entering into hedges, which could reduce the relative effectiveness of our hedges and our profitability. To the extent we incur increased costs or are required to post collateral in periods of rising commodity prices, there could be a corresponding decrease in amounts available for our capital investment program. The changes in the regulation of swaps may also 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 U.S. 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.

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 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 waste products, water and air pollution control procedures, facility siting and construction, 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 to prevent future contamination. 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 treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements. See Item 1A. Risk Factors.

Federal and state occupational safety and health laws require us to organize 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.

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.

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 all levels including US federal, state and local, as well as 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 supply.

Our Operations Hydraulic fracturing techniques have been used by the industry since 1947, and, currently, more than 90% of all 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 aquifers.

We strive to procure non-hydrologic water (water that is not connected to a natural surface stream); 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 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 general public health.

Potential Rulemaking Although hydraulic fracturing is regulated primarily at the state level, governments and agencies at all levels from federal to municipal are conducting studies and considering regulations. 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 2012, the US BLM proposed regulations governing hydraulic fracturing on federal lands, which were withdrawn and then reissued in 2013.

Also during 2012, the EPA proposed 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 for EPA underground injection control permitting.

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 2014.

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. OSHA is working with industry and other government agencies to review existing regulations for applicability to hydraulic fracturing.

In 2012, several 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 where voters chose to ban hydraulic fracturing activities within city limits. Subsequently, the State of Colorado, through the COGCC, sued the City of Longmont in Boulder County District Court to set aside a city ordinance that promulgated stricter oil and gas rules than the COGCC Rules asserting that portions of these rules are preempted by State statutes and COGCC rules. The Colorado Oil and Gas Association (COGA) moved to intervene in this action and intervention was granted. The case is expected to go to trial in 2014.

In the Colorado 2013 general election, the municipalities of Boulder, Broomfield, Fort Collins and Lafayette each passed ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries. The Broomfield election results are under review by State officials for potential voting irregularities. For other communities, the specific prohibitions and moratoria were effective upon passage. The large majority of our DJ Basin acreage is not located in these municipalities and, therefore, we do not expect our operations to be impacted by these developments. However, in the future, should additional Colorado ballot initiatives be undertaken to regulate, limit or ban hydraulic fracturing or other facets of oil and 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 have a potential negative impact on our stock price.

On May 16, 2013, the US Department of the Interior issued proposed rules governing hydraulic fracturing on federal lands. 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.

The proposed 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.

The proposed rules could see further revision. 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.

In Nevada, the State Assembly recently adopted legislation that requires the development of a program to regulate the use of hydraulic fracturing in Nevada. State regulators are in the process of proposing rules and holding public hearings.

We continue to monitor new and proposed legislation and regulations to assess the potential impact on our operations. We are currently evaluating the possible impact any proposed rules, such as those described above, could have on our business. Any additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

Public Disclosure Several states have issued regulations requiring disclosure of certain information regarding the components used in the hydraulic-fracturing process. In 2011, 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 expect to see results of our pilot well program by late 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. Due to the current strong onshore and offshore drilling activity, drilling rigs and hydraulic fracturing crews are in high demand, and there could be delays as we wait for rigs or crews to become available.

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

Competition

The crude oil and natural gas industry is highly competitive. We encounter competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic data and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies, state-controlled national oil companies, independent crude oil and natural gas companies, service companies engaging in exploration and production activities, drilling partnership programs, private equity, and individuals. Many of our competitors are large, well-established companies. Such companies may be able to pay more for seismic information and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See Item 1A. Risk Factors.

Geographical Data

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

Employees

Our total number of employees increased 15%, from 2,190 at December 31, 2012 to 2,527 at December 31, 2013, in support of our major development and exploration projects. The 2013 year-end employee count includes 248 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 China, Cameroon, Equatorial Guinea, Israel, Cyprus, Nicaragua, Falkland Islands, the UK 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, 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 financial, strategic, operational, regulatory, political, and other risks.

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

Available Information

Our website address is *www.nobleenergyinc.com.* Available on this website under “Investors – SEC Filings,” free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, 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 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.

For example, high and low daily average settlement prices for prompt month contracts for crude oil and natural gas during 2013 were as follows:

	Daily Average Settlement Price for Prompt Month Contracts	
	High	Low
Year Ended December 31, 2013		
NYMEX		
Crude Oil - WTI (Per Bbl)	$ 110.53	$ 86.68
Natural Gas - HH (Per MMBtu)	4.46	3.11
Brent		
Crude Oil (Per Bbl)	118.90	97.69

Prices for our US NGL production are determined at two primary market centers, Conway and Mt. Belvieu. For the year ended December 31, 2013, US average realized NGL prices were approximately 35% of average realized crude oil prices and tended to track the volatility of NYMEX WTI.

The application of new drilling technologies in the US has unlocked significant crude oil resources in shale formations, resulting in increased domestic supply. This has resulted in US crude oil prices becoming disconnected from global crude oil price indices such as Brent. Current crude oil forward price curves indicate market expectations are that US oil is likely to continue trading at a discount to global prices.

In addition, changes may occur in regional US crude oil and natural gas markets with the markets moving from being undersupplied (premium prices) to being oversupplied (discounted prices). Regional US supply/demand changes could significantly impact netback charges and, ultimately, project economics. Finally, a current federal export ban on crude oil and/or governmental regulations regarding LNG exports could limit pricing as domestic supply increases.

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;
- 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;
- 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;
- 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, 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 may become economically unviable;
- delay or postponement of some of our capital projects;
- significant reductions in our 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; or
- 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 limit our growth with negative impact on our operating results, liquidity and financial position.

We currently have an extensive 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 recently sanctioned deepwater development projects at Gunflint and Big Bend. Our Leviathan, Cyprus, Carla and Diega discoveries are being appraised and, as such, not yet sanctioned. It will take several years before first production is achieved.

Some projects, such as crude oil and natural gas projects offshore West Africa and the Eastern Mediterranean, 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. Our Leviathan project also includes potential LNG or floating LNG infrastructure. Additionally, we have multiple unsanctioned integrated development plans for our onshore US acreage.

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:

- 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;
- lack of government approval for projects;
- civil disturbances, anti-development activities, legal challenges or other potential interruptions which could prevent access; and
- drilling hazards or accidents or natural disasters.

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

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

We have significant international operations, with approximately 42% of our 2013 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 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 Cyprus, the Falkland Islands, or Nicaragua. 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.

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, additional revenues may be sought to support infrastructure and economic development and for social spending. In many OECD (Organisation for Economic Cooperation and Development) nations, governments are facing significant budget deficits and growing national debt levels, as well as pressure from financial markets to address structural spending imbalances.

In the US, certain measures have been proposed that would alter current tax expense on oil and gas companies, for example: the repeal of percentage depletion for oil and natural gas properties; the deferral of expensing intangible drilling and development costs (IDC); the inability to expense costs of certain domestic production activities; and a lengthening of the amortization period for certain geological and geophysical expenditures. It is likely that some of these proposals to increase tax expense on the oil and gas industry will continue to be reviewed by the US Congress in 2014 or future years. The enactment of some or all of these proposals would have a significant negative impact on our capital investment, production and growth. In particular, we estimate that the elimination of the deductibility of IDC expenditures would impact our cash available for investment and could curtail our domestic capital spending program up to 20%.

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 holding;
- 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.

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 organizations has 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 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.

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 approximately 95% of our current production, and account for approximately 90% of our 2014 capital investment program and most of our exploration potential.

In addition, a large portion of our production is from a relatively few deepwater wells. For example, approximately 40% of our 2013 production came from four offshore developments. Although, individually, none of the core areas represented more than 35% of our 2013 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 result in 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 and natural gas, 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;
- 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, Eastern Mediterranean or offshore China;
- 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; and
- other natural disasters.

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

Offshore development involves significant operational and financial risks.

We have ongoing major development projects in the deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean. In addition, we are conducting offshore exploration activities in these and other 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 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 are currently evaluating potential development scenarios for Leviathan and Cyprus Block 12. Due to the scale of these discoveries, realization of their full economic value depends on the ability to export via pipeline or LNG. Each of these development options would require a multi-billion dollar investment and a number of years to complete.

As a result, we have been seeking partners to provide technical and financial support as well as midstream and downstream expertise. We and our existing partners in the Leviathan project are working on an agreement to sell a portion of our working interests in the Leviathan licenses to Woodside Energy Ltd. (Woodside). The transaction is subject to the negotiations and execution of definitive agreements among the parties, as well as customary government approvals, prior to closing. Failure to reach a definitive agreement with Woodside could result in a delay in the Leviathan development project.

We continue to study the official export and natural gas development policies in Israel and are monitoring any additional developments 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 closing of a farm-out agreement which we and our partners are negotiating with Woodside or preclude such an agreement entirely; and/or render future exploration and development projects uneconomic.

Restrictions on resource access or controls over natural gas pricing could have a negative impact on our business including reduction on future growth rates, profitability and cash flows.

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.

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

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

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

- declines in commodity prices, which reduce revenues and available cash flows;
- changes in fiscal regimes impacting royalties, taxes, fees, resource access, or level of government participation in projects;
- delay in government project approval, 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 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. As required by the Dodd-Frank Act, the Commodities Futures Trading Commission (CFTC) has promulgated numerous rules to define these terms.

In addition, it is possible that the CFTC, in conjunction with US prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in us being required to post collateral.

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; however, given our current investment grade status, none of our current derivative contracts require the posting of margin or similar cash collateral.

Depending on the rules and definitions adopted by the CFTC and prudential regulators, we could be required to post significant amounts of collateral with our dealer counterparties for our derivative transactions. A sudden margin call triggered by rising commodity prices or falling interest rates would have an immediate negative impact on our business plan, forcing us to divert capital from exploration, development and production activities. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and also cause us to incur additional debt and/or reduce capital investment. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability. In addition, the final CFTC rules may also require the counterparties to our derivative instruments to spin off some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty.

We face various risks associated with global populism.

Globally, certain individuals and organizations are attempting to focus public attention on income distribution, 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 a dry hole cost or even drilling incidents;
- 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 and natural gas 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, additional regulation and, in some cases, a moratorium on the use of the technique. Several bills have been filed in the US Congress that, if implemented, would subject hydraulic fracturing to further regulation thereby limiting its use or increasing its cost. 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.

Additionally, some local municipalities have restricted or prohibited drilling activities, or are considering doing so. The U.S. Department of the Interior 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 and possibly implemented before the end of 2014. 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 and natural gas reserves. See Items 1. and 2. Business and Properties – Hydraulic Fracturing.

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

The marketability of our production from our onshore US areas and deepwater Gulf of Mexico depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, rail service, and processing facilities. We deliver crude oil and natural gas produced from these areas through gathering systems and pipelines, some 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 and natural gas 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 Nicaragua and offshore Sierra Leone. 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 and natural gas 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 and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water. For example, the hydraulic fracturing process which we employ to produce commercial quantities of crude oil and natural gas from many reservoirs requires the use and disposal of significant quantities of water. In certain regions, there may be insufficient local capacity to provide a source of water for drilling activities. In those cases, water must be obtained from other sources and transported to the drilling site, adding to the 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, 2013, we had $4.8 billion of long-term debt, of which $258 million is due within 12 months. Our indebtedness represented 35% of our total book capitalization (sum of debt plus shareholders' equity) at December 31, 2013.

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 and we may default on our debt obligations. 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 10. Long-Term Debt.

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, such as a potential LNG project. 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 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 and natural gas 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 and natural gas 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 2014. 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:

- 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.

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 and natural gas reserves are not precise.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas 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 and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows expected from them prepared by different petroleum engineers or by the same petroleum engineers but at different times may vary substantially. Estimation of crude oil and natural gas reserves in emerging areas or areas with limited historical production is inherently more difficult, and we may have less experience in such areas. Accordingly, reserves estimates may be subject to positive or negative revisions, and actual production, revenues and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

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. Even if these challenges can be dealt with successfully, we cannot provide assurance that the anticipated benefits of any acquisition, divestiture or other strategic change may be realized.

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, such as our sale of certain onshore US and North Sea assets in 2013 and 2012. 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 substantial capital expenditures especially in the case of our major development projects. Development of LNG terminals or underwater pipelines for export of gas from Leviathan will require a multi-billion dollar investment. In addition, our CONSOL Carried Cost Obligation requires us to pay one-third of CONSOL's working interest share of certain future drilling and completion costs, up to approximately $2.1 billion, generally during periods in which average Henry Hub natural gas prices are above $4.00 per MMBtu. Major offshore projects have a long development cycle time, which means that development spending occurs for several years before the project begins producing and generating cash flows.

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.

If revenues were to decrease as a result of lower crude oil, natural gas, or NGL prices or decreased production, and/or our access to debt or capital were limited, we would have a reduced ability to replace our reserves, resulting in lower production over time. If our cash flows from operations are not sufficient to meet our obligations and fund our capital investment program, we may not be able to access capital markets on an economic basis to meet these requirements. If we are not able to fund our capital expenditures, 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 – 2014 Capital Investment Program.

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

We are exposed to risk of financial loss from trade, joint venture, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. In addition, we are the operator on a majority of our large joint venture development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs. For example our partners in the Eastern Mediterranean must obtain financing for their share of significant development expenditures at Leviathan, which potentially includes an LNG project 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 $1.1 billion in cash and cash equivalents at December 31, 2013, 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, hedging 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 to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we 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 use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. Interest rates are variable and we may also end up hedging too much or too little when we attempt to effectively fix cash flows related to interest payments on an anticipated debt issuance.

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

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

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

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters 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, 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 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 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 and natural gas. 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 and natural gas 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, as amended, the Resource Conservation and Recovery Act, as amended, 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. Governmental fines or penalties could also be excessive.

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
- 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. 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.

During periods of increasing levels of industry exploration and production, such as is occurring in the DJ Basin and Marcellus Shale, the demand for, and cost of, drilling rigs and oilfield services increases. As exploration and production activity increases, so does the demand pressure for drilling rigs and oilfield services, which could result in sector inflation. In addition, regulatory changes, such as in response to the Deepwater Horizon incident or related to hydraulic fracturing, may also result in reduced availability and/or higher costs for these rigs and services. As a result, drilling rigs and oilfield services may not be available at rates that provide a satisfactory return on our investment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Contractual Obligations*.

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

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

Disclosure Regarding Forward-Looking Statements

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

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

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas 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. At this time, the OOG has not established a proposed penalty for these NOVs or Orders. Given the uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

Colorado Matter In July 2013, we received a proposed Compliance Order on Consent (COC) from Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance with our 2012 Ozone Season submissions pursuant to Air Quality Control Commission Regulation 7. The COC sought payment of a reduced penalty of $156,450. On August 7, 2013, we accepted the reduced penalty and executed the COC. Under the terms and conditions of the COC, we agreed to pursue a supplemental environmental project (SEP) to mitigate $125,160 of the total penalty and submitted payment of $31,290 as an administrative penalty. On November 26, 2013, we provided $125,160 to the American Lung Association of Colorado to serve as funding for the development and implementation of its Clear the Air Challenge, which is a pollution prevention and environmental education program that focuses on the reduction and/or elimination of pollutants, to help preserve the region's air quality through conservation of transportation related energy. All penalties associated with this matter have now been paid.

See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

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

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

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

	High [(1)]	Low [(1)]	Dividends Per Share[(1)]
2012			
First Quarter	$ 52.73	$ 46.79	$ 0.11
Second Quarter	50.49	38.42	0.11
Third Quarter	48.80	41.17	0.11
Fourth Quarter	51.54	45.00	0.12
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

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

On January 28, 2014, the Board of Directors declared a quarterly cash dividend of $0.14 per common share, which will be paid February 24, 2014 to shareholders of record on February 10, 2014.

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 13, 2014, the number of holders of record of our common stock was 623.

Stock Repurchases The following table summarizes repurchases of our common stock occurring fourth quarter 2013.

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)
10/1/2013 - 10/31/13	678	$ 72.00	—	—
11/1/2013 - 11/30/13	531	74.83	—	—
12/1/2013 - 12/31/13	—	—	—	—
Total	1,209	$ 73.25	—	—

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

Equity Compensation Plan Information The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2013.

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	12,677,857	$ 39.82	19,443,748
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	12,677,857	$ 39.82	19,443,748

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2008 to December 31, 2013. 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.

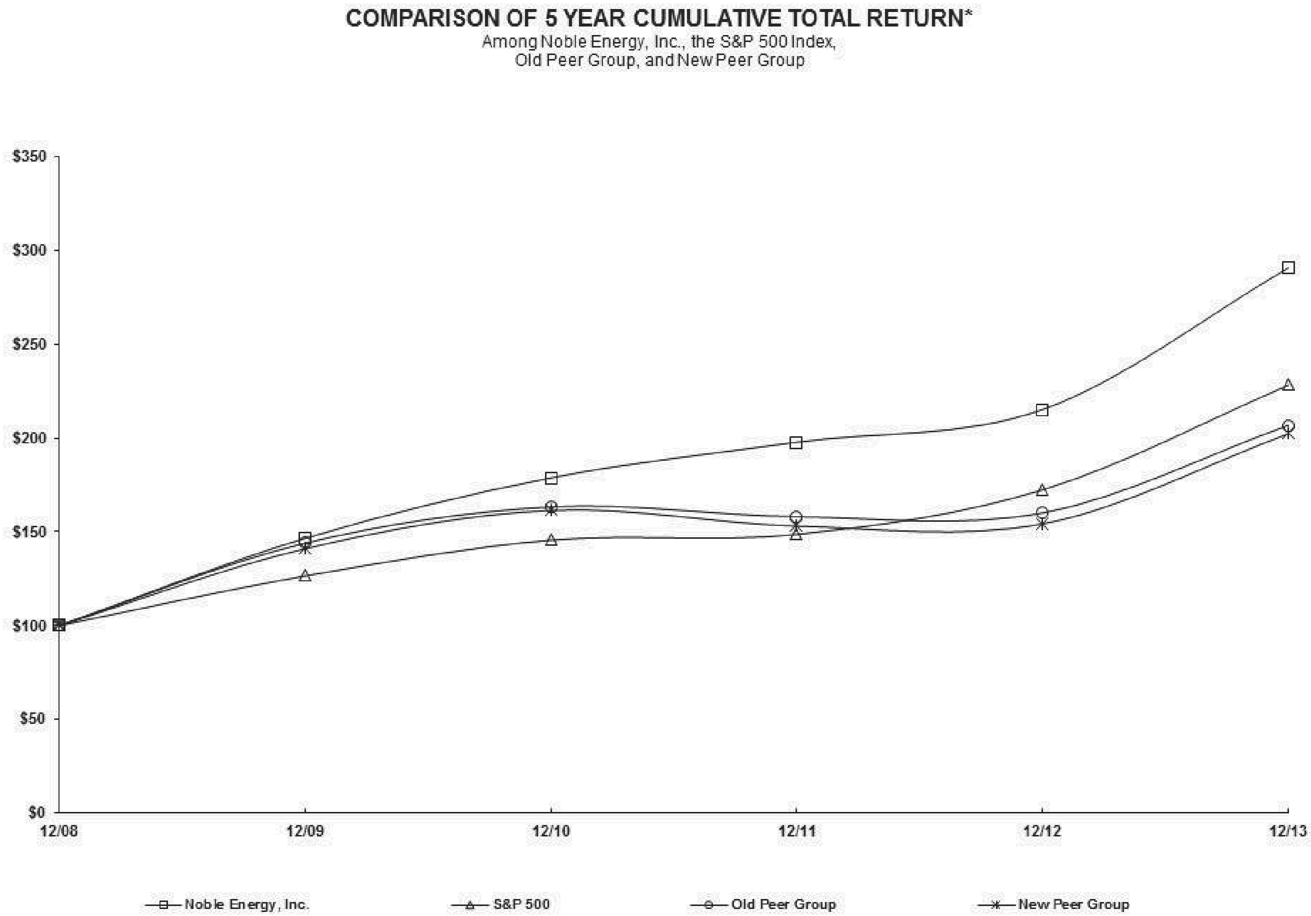
The companies in the old peer group consisted of the following:

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

On January 28, 2013, the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) made changes to our compensation peer group to remove Plains Exploration and Production Company from the old peer group listed above after being acquired by a global mining company, and add Hess Corporation, which is a US company listed on the NYSE with a balance of projects similar in size and scope to ours. After the change in companies, the 2013 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.
Newfield Exploration Company
Noble Energy, Inc.
Pioneer Natural Resources Company
Range Resources Corp.
Southwestern Energy Company

The comparison assumes $100 was invested on December 31, 2008 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.



*$100 invested on 12/31/08 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

Year Ended December 31,	2008	2009	2010	2011	2012	2013
Noble Energy, Inc.	$ 100.00	$ 146.46	$ 178.73	$ 197.75	$ 215.20	$ 290.67
S&P 500	100.00	126.46	145.51	148.59	172.37	228.19
Old Peer Group	100.00	143.92	163.23	158.03	160.08	206.82
New Peer Group	100.00	140.93	161.39	153.07	154.23	202.31

Item 6. Selected Financial Data

	Year Ended December 31,				
(millions, except as noted)	2013	2012	2011	2010	2009
Revenues and Income (Loss)					
Total Revenues	$ 5,015	$ 4,223	$ 3,404	$ 2,713	$ 2,160
Income (Loss) from Continuing Operations	907	965	412	631	(159)
Net Income (Loss)	978	1,027	453	725	(131)
Per Share Data [1]					
Earnings (Loss) Per Share - Basic					
Income (Loss) from Continuing Operations	$ 2.53	$ 2.71	$ 1.17	$ 1.80	$ (0.46)
Net Income (Loss)	2.72	2.89	1.28	2.07	(0.38)
Earnings Per Share - Diluted					
Income (Loss) from Continuing Operations	2.50	2.68	1.15	1.78	(0.46)
Net Income (Loss)	2.69	2.86	1.27	2.05	(0.38)
Cash Dividends Per Share	0.55	0.45	0.40	0.36	0.36
Year-End Stock Price Per Share	68.11	50.87	47.20	43.04	35.61
Weighted Average Shares Outstanding					
Basic	359	356	353	350	347
Diluted	363	359	357	354	347
Cash Flows					
Net Cash Provided by Operating Activities	$ 2,937	$ 2,933	$ 2,170	$ 1,946	$ 1,508
Additions to Property, Plant and Equipment	3,947	3,650	2,594	1,885	1,268
Acquisitions	—	—	527	458	—
Proceeds from Divestitures	327	1,160	77	564	3
Financial Position					
Cash and Cash Equivalents	$ 1,117	$ 1,387	$ 1,455	$ 1,081	$ 1,014
Property, Plant, and Equipment, Net	15,725	13,551	12,782	10,264	8,916
Goodwill	627	635	696	696	758
Total Assets	19,642	17,554	16,444	13,282	11,807
Long-term Obligations					
Long-Term Debt	4,566	3,736	4,100	2,272	2,037
Deferred Income Taxes	2,441	2,218	2,059	2,110	2,076
Asset Retirement Obligations	547	333	344	208	181
Other	562	477	408	422	366
Shareholders' Equity	9,184	8,258	7,265	6,848	6,157
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	99	86	56	54	55
Average Realized Price ($/Bbl) [2]	$ 100.29	$ 101.52	$ 99.17	$ 75.76	$ 55.32
Consolidated Natural Gas Sales (MMcf/d)	901	774	806	781	776
Average Realized Price ($/Mcf) [2]	$ 2.97	$ 2.19	$ 3.00	$ 2.98	$ 2.52
Consolidated NGL Sales (MBbl/d)	16	16	15	14	10
Average Realized Price ($/Bbl)	$ 35.53	$ 35.36	$ 48.35	$ 41.21	$ 27.96
Proved Reserves					
Crude Oil, Condensate and NGL Reserves (MMBbls)	436	357	369	365	336
Natural Gas Reserves (Bcf)	5,828	4,964	5,043	4,361	2,904
Total Reserves (MMBoe)	1,406	1,184	1,209	1,092	820
Number of Employees	2,527	2,190	1,876	1,772	1,630

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

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:

- Executive Overview;
- Operating Outlook;
- Results of Operations;
- Proved Reserves;
- Liquidity and Capital Resources; and
- Critical Accounting Policies and Estimates.

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 and natural gas. 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.

2013 Results In pursuit of our strategy, we progressed our exploration program during 2013 with discoveries of new resources at Karish and Tamar Southwest (offshore Israel), Troubadour and Dantzler (deepwater Gulf of Mexico) as well as drilling successful appraisal wells at Leviathan (offshore Israel), Gunflint (deepwater Gulf of Mexico) and offshore Cyprus.

The continuous growth of our development program has propelled consolidated average sales volumes to 265 MBoe/d for 2013. During the year, we delivered two new major offshore development projects within the budgeted cost and timeline. Our growth is driven by our five core areas which will provide for future growth in the years ahead.

Our accelerated horizontal production in the DJ Basin and ramp up of our Marcellus Shale drilling program continue to generate new production records. The outstanding results of these core areas are the product of efficiency gains and operational expertise in each basin.

In the DJ Basin, we have increased 2013 daily production by 23%, as compared with 2012, through realizing economies of scale through our utilization of integrated development plans that allow us to optimize ultimate resource recovery while decreasing our capital and lease operating costs as well as surface and environmental impact. Additionally, the expansion of our extended reach lateral well program and successful downspacing are further increasing our hydrocarbon recoveries. Our recently completed acreage exchange with another operator in the Basin has provided large contiguous acreage blocks and will allow us to optimize drilling, production and gathering activities for the asset.

In the Marcellus Shale, daily production in 2013 increased over 60% as compared with 2012, largely fueled by leveraging best practices in drilling and completions. For example we have obtained fit-for-purpose rigs and seen substantial cost improvement. During 2013, we increased our drilling activity and brought seven new multi-well pads online. We also expanded our acreage position by acquiring drilling rights to approximately 90,000 gross acres.

Our international assets contributed substantially with world-class reliability from our major projects in both the Eastern Mediterranean and West Africa. Two major projects, Tamar (offshore Israel) and Alen (offshore West Africa), were completed during 2013 and began producing ahead of the sanctioned project schedule. Natural gas from the Tamar field flows through the world's longest subsea tieback, more than 90 miles to the Tamar platform and then to the Ashdod onshore terminal before being sold into the domestic Israeli energy market. Condensate from the Alen field utilizes the Aseng FPSO as a regional hub for storage and offloading to the global market. Tamar and Alen are technical and commercial milestones that significantly contributed to our 14% year over year consolidated production growth.

Our deepwater Gulf of Mexico program is progressing as we sanctioned both Big Bend (phase one of our Rio Grande development) and Gunflint during 2013. We expect that these two major projects will utilize existing host facilities via subsea tiebacks and provide new production in late 2015 and 2016, respectively. We also expect to sanction our Dantzler discovery in 2014. Dantzler will likely include a subsea tieback, potentially leveraging the Big Bend subsea infrastructure. Our Galapagos development, which began production in 2012, continues to perform well.

Our 2013 financial results included:

- net income of $978 million (including $907 million from continuing operations), as compared with $1.0 billion (including $965 million from continuing operations) for 2012;
- gain on divestitures of $36 million, as compared with $154 million for 2012;
- dry hole cost of $149 million, as compared with $155 million for 2012;
- asset impairment charges of $86 million, as compared with $104 million for 2012;
- loss on commodity derivative instruments of $133 million (including unrealized mark-to-market loss of $131 million), as compared with $75 million gain on commodity derivative instruments (including unrealized mark-to-market gain of $109 million) for 2012;
- diluted earnings per share of $2.69, as compared with $2.86 for 2012;
- cash flows provided by operating activities of $2.9 billion, as compared with $2.9 billion in 2012;
- capital spending on a cash basis of $3.9 billion, as compared with $3.7 billion in 2012;
- ending cash and cash equivalents balance of $1.1 billion at December 31, 2013, as compared with $1.4 billion at December 31, 2012;
- issuance of $1.0 billion of 30-year unsecured notes;
- proceeds of $327 million from sales of non-core properties and an acreage exchange, as compared with sales proceeds of $1.2 billion in 2012;
- total liquidity of $5.1 billion at December 31, 2013, consisting of year-end cash balance plus funds available under our Credit Facility, as compared with $5.4 billion at December 31, 2012; and
- year-end ratio of debt-to-book capital of 35%, as compared with 33% at December 31, 2012.

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 high-value and high-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, including onshore US and North Sea properties, generated proceeds of approximately $1.4 billion during the last two years, including $206 million during 2013. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

Sales Volumes The execution of our business strategy, including production start-up at our Tamar and Alen projects and accelerated activity in onshore US unconventional projects, has delivered well diversified production growth . On a BOE basis, total sales volumes from continuing operations were 14% higher in 2013 as compared with 2012, and our mix of sales volumes in 2013 was 43% global crude oil and NGLs, 29% international natural gas, and 28% US natural gas. See Results of Operations – Revenues, below.

Commodity Price Changes and Hedging Although crude oil, natural gas and NGL prices have historically exhibited significant volatility, the markets remained relatively stable during 2013. Domestic crude oil prices rose steadily into the summer, followed by a few months of decline towards the end of the year, but finished 2013 with modest growth compared to 2012 year-end prices. Total consolidated average realized crude oil prices for 2013 decreased 1% as compared with 2012, due to slight declines in Brent pricing. In the US domestic natural gas pricing continues to improve. Natural gas prices rose sharply early in the year, followed by a steady decline during the summer months, followed by steadily rising prices over the fourth quarter as below normal temperatures across the US increased consumption. US average realized natural gas prices for 2013 increased 36% as compared with 2012.

To enhance the predictability of our cash flows and support our capital investment program, we have hedged a portion of our expected global crude oil and natural gas production for 2014 and 2015. 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 pre-tax realized gains and losses, which equal cash settlements during the period, and pre-tax, unrealized, non-cash gains or losses which are due to the change in the mark-to-market value of our commodity contracts. Unrealized mark-to-market gains or losses recognized in the current period will be realized in the future when they are settled in cash at maturity date. The amount of gain or loss actually realized may be more or less than the amount of unrealized mark-to-market gain or loss previously reported. The use of mark-to-market accounting adds volatility to our net income. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Asset Impairment Charges During 2013, we recorded impairment charges of $86 million primarily related to our Mari-B field, offshore Israel, due to natural field decline, and certain non-core onshore US properties divested during the year and assets held for sale at December 31, 2013. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

OPERATING OUTLOOK

2014 Outlook Global crude oil and US natural gas prices are historically volatile based on supply and demand dynamics. We expect global crude oil production volumes to continue to grow, primarily due to increases in the US supply from continued application of horizontal drilling technology. This growth coupled with potential supply in North Africa and the Middle East returning to the market may result in an increase in OPEC spare production capacity, a key determinant of global crude oil prices. Meanwhile, political risk in key producer nations remains high and numerous producer nations have significant crude oil supply offline. North African and Middle East conflicts, civil unrest, and other potential supply interruption risks are likely to continue and can have a significant impact on crude oil supplies. Meanwhile, global crude oil demand is expected to grow in 2014 as the global economy continues to expand. Global crude oil prices will be determined by these supply and demand factors. In the US, de-bottlenecking of oil transportation routes in the Mid-Continent will increase Gulf Coast supply; as a result, we may see continued volatility among US grades and discount pricing compared with Brent.

In the US, we expect natural gas prices to be range-bound as supply continues to grow, particularly in the northeast from Marcellus Shale and Utica Shale production, and new sources of industrial, power and other demand come on line over the next several years. Longer term, the amount of LNG export capacity approved, sanctioned for investment and built will also be a market consideration.

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 flexible capital spending program coupled with our commodity hedging programs, which will support both major project development and exploration activities in a volatile commodity price environment. See 2014 Capital Investment Program, below.

2014 Production Our expected crude oil, natural gas and NGL production for 2014 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;
- changes to drilling plans in the DJ Basin and the Marcellus Shale;
- 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 non-core onshore US areas and the Alba and Aseng fields offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico, heat in the Rocky Mountain area of our US operations, or winter storms and flooding in the DJ Basin, Marcellus Shale and/or Rocky Mountain areas;
- 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;
- 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.

2014 Capital Investment Program Total capital expenditures are estimated at $4.8 billion for 2014. We expect to invest $3.2 billion, or approximately 70% of the program, in onshore US development and $1.5 billion, or approximately 30% of the program, in global deepwater activities.

The 2014 capital investment program is anticipated to exceed operating cash flows and is expected to be funded from cash flows from operations, cash on hand, and borrowings under our Credit Facility and/or other financing such as an issuance of long-term debt. Funding may also be provided by proceeds from divestment of non-core assets and farming out working interests in exploration prospects. See Liquidity and Capital Resources – Financing Activities.

We will evaluate the level of capital spending and remain flexible throughout the year based on the following factors, among others:

- commodity prices, including price realizations on specific crude oil and natural gas production including the impact of NGLs;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- 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;
- increase in exploration activities in new areas, including offshore Sierra Leone and the Falkland Islands;
- availability of financing;
- 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, including implementation of the Dodd-Frank Wall Street Reform and Consumer Protection Act, which has resulted in significant derivatives regulations and disclosure requirements, on our business practices.

Exploration Program We continue to evaluate and build upon our significant exploration inventory in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other international locations. During 2013, we drilled successful exploratory wells at Troubadour and Dantzler in the deepwater Gulf of Mexico, as well as Karish and Tamar Southwest offshore Israel.

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 significant remaining exploration upside. We continue to leverage existing activities to improve our exploratory programs in these core areas.

We devote significant capital to our exploration program. Approximately 10% of our $4.8 billion capital investment program in 2014 is dedicated to exploration and associated appraisal activities. However, 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. For example, during 2013 we drilled the Paraiso-1 exploratory well, offshore Nicaragua, which did not encounter commercial quantities of hydrocarbons.

We are currently conducting, or planning to conduct, exploratory drilling activities in previously unexplored areas as well as appraisal activities at several of our discoveries. In the event we conclude that one of our exploratory wells did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. 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 in 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. As a result, in a future period, dry hole cost and/or leasehold impairment charges could be significant. See Results of Operations – Oil and Gas Exploration Expense, below. See also Item 1A. Risk Factors.

Major Development Project Inventory Our current inventory of major development projects includes the horizontal Niobrara, Marcellus Shale, Diega and Carla, Gunflint, Rio Grande (Big Bend and Dantzler), Leviathan, Tamar Expansion, Tamar Southwest, and Cyprus. These projects will require significant capital investments.

As noted above, we expect to spend substantial amounts on our major development projects in 2014. We plan to fund these projects from cash flows from operations, borrowings under our Credit Facility, proceeds from divestments of non-core assets, cash on hand, and/or other financing.

The additional production from our major development projects brought online since 2011 has begun generating significant cash flow which is being utilized to meet a substantial portion of capital requirements. 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, including our partners in our Eastern Mediterranean projects, may not be as creditworthy as we are and may experience liquidity problems. 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 We recorded asset impairment charges of $86 million during 2013. A decline in future crude oil or natural gas prices could result in additional impairment charges. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future crude oil and natural gas production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward crude oil or natural gas prices alone could result in impairment.

We are currently marketing certain non-core onshore US properties. If the properties are reclassified as assets held for sale, 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. Goodwill write-offs result in an increase in our effective tax rate because goodwill is nondeductible for US federal income tax purposes.

Occasionally, well mechanical problems arise, which can reduce production and potentially result in reductions in proved reserves estimates. For example, our South Raton development in the deepwater Gulf of Mexico is currently shut-in due to mechanical issues. We are currently testing the well to determine appropriate remediation efforts. South Raton had a net book value of approximately $117 million at December 31, 2013.

See Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

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 greenhouse gas emissions (GHGs) may pose a risk to the environment.

The 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. The plan, among other things, aims to: establish carbon emission standards for both new and existing power plants; support renewable energy projects and innovative technologies; set new energy efficiency standards for appliances and federal buildings; develop fuel economy standards for heavy-duty vehicles; reduce hydrofluorocarbons; develop a comprehensive methane strategy; update certain flood-risk reduction standards for all federally funded projects; and expand major new and existing international initiatives, including bilateral initiatives with China, India, and other major carbon emitting countries.

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.

While no specific new international climate change 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 2013 total sales volumes from continuing operations. The burning of natural gas produces lower levels of emissions than other readily available fuels such as liquid hydrocarbons and coal. In addition, public concern about nuclear safety has increased. These factors could increase the demand for natural gas as fuel for power generation. Also, should renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply.

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

Finally, future GHG standards for vehicles, could result in the use of natural gas as transportation fuel. This may also increase the market demand for natural gas. 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. See Discontinued Operations, below. Financial information presented is from continuing operations, unless otherwise noted.

Selected financial information is as follows:

	Year Ended December 31,		
	2013	2012	2011
(millions, except per share)			
Total Revenues	$ 5,015	$ 4,223	$ 3,404
Total Operating Expenses	3,359	2,811	2,870
Operating Income	1,656	1,412	534
Total Other (Income) Expense	312	56	32
Income from Continuing Operations Before Income Taxes	1,344	1,356	502
Income from Continuing Operations	907	965	412
Discontinued Operations, Net of Tax	71	62	41
Net Income	978	1,027	453
Earnings from Continuing Operations Per Share			
Basic	2.53	2.71	1.17
Diluted	2.50	2.68	1.15

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

Revenues

Oil, Gas and NGL Sales An analysis of the factors contributing to the changes in revenues from sales of crude oil, natural gas and NGLs is as follows:

	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
2011 Sales Revenues	$ 2,034	$ 883	$ 262	$ 3,179
Changes due to				
Increase (Decrease) in Sales Volumes	1,097	(34)	28	1,091
Increase (Decrease) in Sales Prices	74	(229)	(78)	(233)
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 in revenue are discussed below.

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

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2013							
United States	63	440	16	153	$ 96.53	$ 3.54	$ 35.53
Equatorial Guinea (1)	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 (2)	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 (1)	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 (2)	2	—	5	7	104.56	—	69.14
Total Continuing Operations	88	774	21	239	$ 101.58	$ 2.19	$ 44.15
Year Ended December 31, 2011							
United States	38	388	15	117	$ 95.19	$ 3.90	$ 48.35
Equatorial Guinea (1)	14	245	—	56	107.57	0.27	—
Israel	—	173	—	29	—	4.86	—
China	4	—	—	4	106.19	—	—
Total Consolidated Operations	56	806	15	206	99.17	3.00	48.35
Equity Investees (2)	2	—	5	7	108.76	—	72.71
Total Continuing Operations	58	806	20	213	$ 99.46	$ 3.00	$ 54.84

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

(2) 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 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 of 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.

Revenues from crude oil and condensate sales increased by $1.2 billion, or 58%, in 2012 as compared with 2011 due to the following:

- higher sales volumes in the DJ Basin attributable to the acceleration of our horizontal drilling programs onshore US;
- commencement of production at Galapagos and South Raton in the deepwater Gulf of Mexico which increased production by approximately 7 MBoe/d, net, during 2012;
- higher sales volumes in Equatorial Guinea due to the commencement of oil production at Aseng during the fourth quarter of 2011, which impacted our sales volumes by approximately 21 MBbl/d, net, in 2012 as compared with 2011; and
- a 2% increase in total consolidated average realized prices primarily due to higher Brent pricing resulting from the global economic recovery;

partially offset by:

- reduction in sales volumes due to the sales of non-core, onshore US properties during the third quarter of 2012;
- a volume reduction in the Gulf of Mexico of nearly 7 MBoe/d as a result of shut-ins due to Hurricane Isaac; 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 $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 the first quarter of 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.

Revenues from natural gas sales decreased by $263 million, or 30%, in 2012 as compared with 2011 due to the following:

- decreases in US average realized prices primarily due to oversupply and above average levels of natural gas in storage;
- lower sales volumes due to the sales of non-core onshore US properties during the third quarter of 2012;
- lower sales volumes in the DJ Basin and Rocky Mountain area of our US operations due to third-party processing facility constraints;
- lower sales volumes from the Alba field, offshore Equatorial Guinea, due to scheduled maintenance activities at the non-operated Alba facilities; and
- lower sales volumes in Israel due to a reduction in the rate of production from the Mari-B field in order to manage the reservoir;

partially offset by:

- higher sales volumes attributable to the acceleration of our horizontal drilling programs in the DJ Basin; and
- new sales volumes from Marcellus Shale producing properties, which we acquired September 30, 2011 and current Marcellus Shale development activities, which added 90 MMcf/d, net to our sales volumes for 2012.

NGL Sales Most of our US NGL production is from the DJ Basin. 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.

NGL sales revenues decreased $50 million, or 19%, during 2012 as compared with 2011 as a result of lower realized prices offset by an increase in sales volumes. Our average realized prices declined 27% during 2012 compared with 2011 primarily due to higher supplies of NGLs resulting from increased wet gas drilling activities.

Income from Equity Method Investees We have a 45% interest in AMPCO, which owns and operates a methanol plant and related facilities, and a 28% interest in Alba Plant, which owns and operates an LPG processing plant. Both plants and related facilities are located onshore Bioko Island in Equatorial Guinea. We also have a 50% interest in CONE Gathering LLC (CONE), which owns and operates natural gas gathering facilities servicing our joint venture properties in the Marcellus Shale. We account for investments in entities that we do not control but over which we exert significant influence using the equity method of accounting.

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

	Year Ended December 31,		
	2013	2012	2011
Net Income (in millions)			
AMPCO and Affiliates	$ 85	$ 64	$ 68
Alba Plant	121	122	125
Dividends (in millions)			
AMPCO and Affiliates	82	70	86
Alba Plant	122	130	139
Sales Volumes			
Methanol (MMgal)	155	156	155
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	6	5	5
Average Realized Prices			
Methanol (per gallon)	$ 1.27	$ 1.07	$ 1.05
Condensate (per Bbl)	105.37	104.56	108.76
LPG (per Bbl)	68.12	69.14	72.71

AMPCO and Affiliates 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.

Net income from AMPCO and affiliates decreased in 2012 as compared with 2011 primarily due to increased other non-operating expense.

Alba Plant Net income from Alba Plant in 2013 was consistent with 2012.

Net income from Alba Plant decreased slightly in 2012 as compared with 2011 due to lower realized price.

CONE Gathering LLC Under the terms of the gathering and marketing agreement that we entered into with CONE, we pay CONE a minimum annual revenue commitment (MARC). The fee is adjusted annually based on projected gathering volumes, operating expenses, capital expenditures, and other factors. Our share of CONE earnings are netted within our transportation and gathering expense. During 2013, we contributed $48 million to CONE. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2013	Inc (Dec) from Prior Year	2012	Inc (Dec) from Prior Year	2011
Production Expense	$ 850	26 %	$ 673	21 %	558
Exploration Expense	415	1 %	409	48 %	277
Depreciation, Depletion and Amortization	1,568	14 %	1,370	56 %	878
General and Administrative	433	13 %	384	13 %	339
Gain on Divestitures	(36)	(77)%	(154)	516 %	(25)
Asset Impairments	86	(17)%	104	(86)%	757
Other Operating (Income) Expense, Net	43	72 %	25	(71)%	86
Total	$ 3,359	19 %	$ 2,811	(2)%	2,870

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [1]	Total	United States	Equatorial Guinea	Israel	Other Int'l/ Corporate [2]
Year Ended December 31, 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
Year Ended December 31, 2011						
Lease Operating Expense [3]	$ 4.47	$ 346	$ 254	$ 53	$ 12	$ 27
Production and Ad Valorem Taxes	1.88	146	102	—	—	44
Transportation and Gathering Expense	0.85	66	63	—	—	3
Total Production Expense	$ 7.20	$ 558	$ 419	$ 53	$ 12	$ 74
Total Production Expense per BOE		$ 7.20	$ 9.85	$ 2.64	$ 1.16	N/M

N/M Amount is not meaningful. See [2] below.

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

(2) Other Int'l/Corporate includes China and unallocated expenses incurred at the corporate level.

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

Lease Operating Expense 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;
- 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 of 2013;

partially offset by:

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

Lease operating expense increased in 2012 as compared with 2011 due to the following:

- higher sales volumes from the DJ Basin due to ongoing development activities accounted for an increase of $24 million in US lease operating expense;
- new production at Galapagos and higher production handling costs at Swordfish, deepwater Gulf of Mexico, accounted for an increase of $22 million;
- a full year of production from Marcellus Shale properties acquired in 2011, and additional development activity accounted for an increase of $17 million;
- lease operating expense associated with the Aseng field, offshore Equatorial Guinea, which began producing in November 2011, accounted for an increase of $36 million; and
- the start-up of the Noa and Pinnacles wells, offshore Israel, in second quarter of 2012 accounted for an increase of $8 million;

partially offset by:

- lower volumes in the US due to the sale of non-core onshore US properties during the third quarter of 2012.

Production and Ad Valorem Tax Expense In the US, production and ad valorem taxes 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.

Production and ad valorem tax expense increased in 2012 as compared with 2011 due to the enactment of the Pennsylvania well impact fee. This enactment increased taxes approximately $8 million, of which approximately $4 million related to wells spud prior to 2012. Additionally, higher volumes for the DJ Basin resulted in an increase of $15 million. This increase was offset by non-core onshore US property sales during 2012.

Transportation Expense 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.

Transportation expense increased in 2012 as compared with 2011 due to higher US crude oil sales volumes from the DJ Basin as a result of ongoing development activities resulted in an increase of $21 million. A full year of production from our Marcellus Shale producing properties, acquired on September 30, 2011, resulted in an increase of $8 million. These increases were offset by reductions in transportation expense due to non-core onshore US property sales during the third quarter of 2012.

Unit Rate Per BOE 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.

The unit rate of total production expense per BOE increased for 2012 as compared with 2011 primarily due to a change in the mix of production, including new production at Galapagos and South Raton, and the start-up of the Noa and Pinnacles wells, each of which has a higher cost to operate than our other projects, and the enactment of the Marcellus Shale well impact fee.

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, 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
Year Ended December 31, 2011					
Dry Hole Cost	$ 105	$ 46	$ 59	$ —	$ —
Seismic	63	33	1	4	25
Staff Expense	94	22	7	2	63
Other	15	15	—	—	—
Total Exploration Expense	$ 277	$ 116	$ 67	$ 6	$ 88

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone, 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 and offshore Falkland Islands.

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 our exploration programs offshore Cyprus and offshore Falkland Islands; and
- staff expense associated with new ventures and corporate expenditures.

Oil and gas exploration expense increased in 2012 as compared with 2011. Expense for 2012 includes the following:

- US dry hole cost related primarily to the Deep Blue exploratory well (deepwater Gulf of Mexico);
- West Africa dry hole cost related to the Trema exploratory well, offshore West Africa, which found noncommercial quantities of hydrocarbons;
- exploration expense in West Africa includes $40 million for the non-operated AGC Profond block offshore Senegal/ Guinea-Bissau, which was written off during the third quarter of 2012 when we decided not to proceed with additional appraisal activities;
- seismic expenditures related to the deepwater Gulf of Mexico lease sale and international new ventures; and
- exploration expense also includes staff expense associated with new ventures and corporate expenditures.

Exploration expense included stock-based compensation expense of $15 million in 2013, $12 million in 2012, and $11 million in 2011.

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

	Year Ended December 31,		
(millions, except unit rate)	2013	2012	2011
United States	$ 1,117	$ 929	$ 732
Equatorial Guinea	261	255	69
Israel	97	111	25
Other International, and Corporate	93	75	52
Total DD&A Expense [1]	$ 1,568	$ 1,370	$ 878
Unit Rate per BOE [2]	$ 16.18	$ 16.16	$ 11.32

[1] DD&A expense includes accretion of discount on asset retirement obligations of $26 million in 2013, $22 million in 2012, and $13 million in 2011.

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

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;
- 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 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.

Total DD&A expense increased for 2012 as compared with 2011 due to the following:

- higher sales volumes in the DJ Basin accounted for $189 million of the increase and the addition of DD&A expense related to the Marcellus Shale accounted for $46 million of the increase;
- the start up of Noa and Pinnacles (offshore Israel), which have higher DD&A rates, accounted for $86 million of the increase;
- the start up of Galapagos and South Raton in the deepwater Gulf of Mexico, which have higher DD&A rates, accounted for $92 million of the increase;
- a full year of production from the Aseng field, offshore Equatorial Guinea, which includes the Aseng FPSO in its depreciation base, accounted for $183 million of the increase; and
- higher costs associated with development activities in China;

partially offset by:

- the impact of sales of non-core, onshore US properties during 2012.

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

	Year Ended December 31,		
	2013	2012	2011
G&A Expense (millions)	$ 433	$ 384	$ 339
Unit Rate per BOE [1]	4.47	4.53	4.37

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

G&A expense for 2013 increased 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 increased for 2012 as compared with 2011 primarily due to additional personnel and office space supporting growth in the DJ Basin and Marcellus Shale and augmentation of environmental, health and safety, geoscience, and information technology departments in support of our major development projects and increased exploration activities, and increased performance incentive compensation.

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 $58 million in 2013, $48 million in 2012 and $42 million in 2011. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

Gain on Divestitures Gain on divestitures was as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Gain on Divestitures	$ (36)	$ (154)	$ (25)

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. Acquisitions and Divestitures. 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)	2013	2012	2011
Asset Impairments	$ 86	$ 104	$ 757

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 Expense, Net Other operating expense, net was as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Deepwater Gulf of Mexico Moratorium Expense	$ —	$ —	$ 18
Electricity Generation Expense	—	—	26
Other (Income) Expense, Net	43	25	42
Total	$ 43	$ 25	$ 86

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

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

	Year Ended December 31,		
(millions)	2013	2012	2011
(Gain) Loss on Commodity Derivative Instruments	$ 133	$ (75)	$ (42)
Interest, Net of Amount Capitalized	158	125	65
Other Non-Operating (Income) Expense, Net	21	6	9
Total	$ 312	$ 56	$ 32

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

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

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

	Year Ended December 31,		
(millions, except per unit)	2013	2012	2011
Interest Expense	$ 279	$ 276	$ 197
Capitalized Interest	(121)	(151)	(132)
Interest Expense, Net	$ 158	$ 125	$ 65
Unit Rate per BOE [1]	$ 1.63	$ 1.48	$ 0.84

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

Interest expense prior to the reduction of capitalized interest remained flat in 2013 as compared with 2012. A reduction in CONSOL installment payments outstanding was offset by an issuance of new senior debt in November 2013. We drew down amounts under our Credit Facility during third quarter and repaid with proceeds from the debt issuance. There were no other significant changes in our debt.

Interest expense prior to the reduction of capitalized interest increased $79 million in 2012 as compared with 2011 resulting from our December 2011 debt issuance, an additional month of interest for our February 2011 debt issuance and interest related to our Aseng FPSO lease obligation.

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.

The increase of $19 million in the amount of interest capitalized in 2012 compared with 2011 is due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and Eastern Mediterranean.

Interest is capitalized on exploration and development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest is related to long lead-time projects in the deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

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

Deferred Compensation (Income) Expense We have assets and liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of our common stock and mutual fund investments. At December 31, 2013, approximately 50% 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 expense of $26 million in 2013, $6 million in 2012, and $8 million in 2011. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Income Tax Provision	$ 437	$ 391	$ 90
Effective Rate	32.5%	28.8%	17.9%

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

Discontinued Operations

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Oil and Gas Sales	$ 37	$ 208	$ 357
Less:			
Production Expense	19	44	58
DD&A Expense	2	33	87
Other (Income) Expense, Net [1]	4	30	(3)
Income Before Income Taxes	12	101	215
Income Tax Expense (Benefit)	6	55	174
Operating Income, Net of Tax	6	46	41
Gain on Sale, Net of Tax	65	16	—
Discontinued Operations, Net of Tax	$ 71	$ 62	$ 41
Key Statistics:			
Daily Production			
Crude Oil & Condensate (MBbl/d)	1	5	8
Natural Gas (MMcf/d)	2	4	5
Average Realized Price			
Crude Oil & Condensate (Per Bbl)	$ 108.73	112.94	112.97
Natural Gas (Per Mcf)	10.65	8.62	8.11

(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 have not allocated interest expense to discontinued operations.

See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

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,		
	2013	2012	2011
(MMBoe)			
Proved Reserves Beginning of Year	1,184	1,209	1,092
Revisions of Previous Estimates	95	(97)	(50)
Extensions, Discoveries and Other Additions	250	218	180
Purchase of Minerals in Place	24	—	68
Sale of Minerals in Place	(47)	(57)	—
Production	(100)	(89)	(81)
Proved Reserves End of Year	1,406	1,184	1,209

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, 2013 included positive performance revisions of 48 MMBoe for the DJ Basin and Marcellus Shale programs, 11 MMBoe for Alba field, and 21 MMBoe for the Tamar field, and positive price revisions of 13 MMBoe due to increases in commodity prices;
- 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; and
- changes for the year ended December 31, 2011 include a negative revision of 28 MMBoe, due primarily to reclassifications of proved undeveloped reserves in the DJ Basin that are no longer expected to be developed within five years due to additional shifting of activity from vertical to horizontal development, a negative revision of 10 MMBoe due to reduced activity assumptions for dry gas properties onshore US, as well as other lesser revisions in various other areas related to well performance and 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, 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.
- 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; and
- changes for the year ended December 31, 2011 included increases of 97 MMBoe in the onshore US, primarily associated with horizontal drilling in the DJ Basin and development activities in the Marcellus Shale, 80 MMBoe at the Tamar field due to appraisal activities, and 3 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 both core areas and global new ventures programs. We may also purchase proved properties in strategic acquisitions. See Operating Outlook – Major Development Project Inventory, above, and Liquidity and Capital Resources – Acquisition, Capital and Other Exploration Expenditures, below.

Purchase of Minerals in Place We occasionally enhance our asset portfolio with strategic acquisitions of producing properties. Purchases included the following:

- the acquisition of additional acreage primarily in the Marcellus Shale and DJ Basin in 2013; and
- the Marcellus Shale asset acquisition in 2011.

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

- the sales 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 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 development and monetize our discovered hydrocarbons, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the volatile commodity price cycle. 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 robust exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an 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 unsecured revolving credit facility (Credit Facility), and proceeds from sales of non-core properties, such as certain onshore US and North Sea properties in 2013 and 2012. We may also access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Credit Facility and to refinance scheduled debt maturities, which includes $200 million due on April 15, 2014. See *Credit Facility,* below.

Expanded development in the DJ Basin and Marcellus Shale, investment in our recently sanctioned major projects, and our planned exploration and appraisal drilling activities will result in near term capital expenditures exceeding cash flows from operating activities. The extent to which capital investment will continue to exceed operating cash flows depends on our success in sanctioning future development projects, the results of our exploration activities, and new business opportunities as well as external factors such as commodity prices, among others. Our financial capacity, coupled with our diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

To support our investment program, we expect that higher production resulting from our horizontal Niobrara development program combined with new production from Tamar, which began producing late in the first quarter of 2013, and Alen, which began producing late in the second quarter of 2013, will result in an increase in cash flows which will be available to meet a substantial portion of future capital commitments. Cash on hand at December 31, 2013 totaled $1.1 billion, and includes both domestic and foreign cash. To the extent cash held by our foreign subsidiaries is not required for foreign investment projects and we would not incur additional US tax, we may consider repatriating some of our foreign cash to increase our financial flexibility and fund our capital investment program.

We also evaluate potential strategic farm-out arrangements of our working interests in Israel, Cyprus, Cameroon, Nicaragua and the deepwater Gulf of Mexico for reimbursement of our capital spending in these areas. In addition, our current liquidity level and balance sheet, along with our ability to access the capital markets, such as our recent $1.0 billion debt offering on November 8, 2013, provide flexibility. We believe that we are well-positioned to fund our long-term growth plans.

We are currently evaluating potential development scenarios for our significant natural gas discoveries offshore Eastern Mediterranean, including Leviathan and Cyprus Block 12. The magnitude of these discoveries presents technical and financial challenges for us due to the large-scale development requirements. Potential development scenarios may include the construction of subsea pipeline, floating LNG, LNG terminals, FPSO or other options. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. We and our Leviathan partners have announced a potential strategic partner for Leviathan, Woodside, who could provide midstream expertise as well as LNG project execution, marketplace expertise and financial capacity.

See *Credit Facility,* below. See also Item 1A. Risk Factors

Pension Plan Termination   Our pension and restoration plans are in the process of being terminated. We expect to liquidate the associated obligations through lump-sum payments to participants. As of December 31, 2013, the accumulated benefit obligations totaled approximately $394 million and the fair value of plan assets was $265 million, leaving approximately $129 million unfunded. We expect to make additional contributions to the plans during the next 12 to 24 months to the extent necessary to fund these obligations.

In addition, upon plan termination, all unamortized prior service cost and net actuarial loss remaining in AOCL will be charged to expense. These amounts totaled approximately $144 million at December 31, 2013. See Item 8. Financial Statements and Supplementary Data - Note 12. Stock-Based and Other Compensation Plans.

Marcellus Shale Joint Venture Our joint venture arrangement with a subsidiary of CONSOL Energy, Inc. is structured in a manner to address partner alignment and financial affordability. The $2.1 billion CONSOL Carried Cost Obligation is expected to extend over a multi-year period and is capped at $400 million in each calendar year. The 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 will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices.

Due to the natural gas prices, we did not make any payments towards the CONSOL Carried Cost Obligation in 2012 or 2013. However, early winter weather drove an increase in natural gas prices to above $4.00 per MMBtu at the end of 2013, and continuation of this price throughout early 2014. Based on the December 31, 2013 Henry Hub natural gas price strip, and our current development plan, we forecast our CONSOL Carried Cost Obligation may commence in March 2014 and total up to approximately $225 million for 2014. See Off-Balance Sheet Arrangements below. See Item 8. Financial Statements and Supplementary Data – Note 3. Property Transactions.

Available Liquidity Information regarding cash and debt balances was as follows:

	December 31,		
	2013	2012	2011
(millions, except percentages)			
Cash and Cash Equivalents	$ 1,117	$ 1,387	$ 1,455
Amount Available to be Borrowed Under Credit Facility (1)	4,000	4,000	3,000
Total Liquidity	$ 5,117	$ 5,387	$ 4,455
Total Debt (2)	$ 4,843	$ 4,123	$ 4,495
Total Shareholders' Equity	9,184	8,258	7,265
Ratio of Debt-to-Book Capital (3)	35%	33%	38%

(1) See *Credit Facility,* below.

(2) Total debt includes capital lease and other obligations and remaining CONSOL installment payments (at December 31, 2012 and 2011) 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.

Cash and Cash Equivalents We had approximately $1.1 billion in cash and cash equivalents at December 31, 2013, compared with approximately $1.4 billion at December 31, 2012. At December 31, 2013 our cash was primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $810 million of this cash is attributable to our foreign subsidiaries, some of which may be subject to US income taxes if repatriated. During 2014, we currently expect to use a portion of cash to fund international projects, while a significant amount will be used towards our onshore US development.

Credit Facility We recently amended our Credit Facility to mature on October 3, 2018. The commitment is $4.0 billion through the maturity date of the Credit Facility. 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 crude oil and 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.

Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. We net settle by counterparty based on master agreements. The net settlements take into account deferred premiums we have agreed to pay for put options. None of our counterparty agreements contain margin requirements. We have also used derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. However, we currently have no interest rate derivative instruments. See Item 1A. Risk Factors.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of December 31, 2013, the fair value of our commodity derivative assets was $17 million and the fair value of our commodity derivative liabilities was $75 million (after consideration of netting clauses within our master agreements). See Item 1A. Risk Factors.

See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Counterparty Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedging 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. 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, which potentially includes an LNG project and/or major underwater pipeline. We are considering assisting our current Leviathan partners, under certain conditions, to obtain appropriate financing for their share of development costs. See Item 1A. Risk Factors.

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. Nonperformance by a trade creditor, joint venture partner, hedging counterparty or financial institution could result in significant financial losses.

Accounts Receivable We have accounts receivable from sales of our crude oil, natural gas and NGLs. We also have accounts receivable from joint venture partners for their share of expenses on joint venture projects for which we are the operator. Some of these parties 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, letters of credit or credit insurance, including our largest crude oil purchaser; 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 losses. We currently have no significant collection issues with purchasers or joint venture partners. See Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data – Note 5. Allowance for Doubtful Accounts.

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2013	2012	2011
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 2,937	$ 2,933	$ 2,170
Investing Activities	(3,675)	(2,527)	(3,113)
Financing Activities	468	(474)	1,317
(Decrease) Increase in Cash and Cash Equivalents	$ (270)	$ (68)	$ 374

Operating Activities Net cash provided by operating activities for 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. See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows.

Net cash provided by operating activities in 2012 increased $763 million, or 35% as compared with 2011. Sales revenues were higher due to increases in commodity prices and sales volumes.

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 $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 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, representing an increase of $529 million as compared with 2011. A significant portion of the spending was related to our major development activity in the DJ Basin, the Marcellus Shale, offshore

West Africa and offshore Israel. We also invested $41 million in CONE during 2012. In addition, we received $1.2 billion proceeds from non-core asset divestitures during 2012 as compared with $77 million proceeds, during 2011.

In 2011, our capital spending totaled $3.2 billion, including $596 million spent on the Marcellus Shale asset acquisition. A significant portion of the spending was related to our major development projects. We received $77 million total proceeds from asset divestitures.

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 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 the final CONSOL installment payment ($328 million), pay dividends on our common stock ($198 million), make principal payments related to the Aseng FPSO capital lease obligation ($48 million), 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 the first CONSOL installment payment ($328 million), pay dividends on our common stock ($164 million), make principal payments related to the Aseng FPSO capital lease obligation ($45 million), repurchase shares of our common stock ($13 million) and other ($5 million).

In 2011, net cash provided by financing activities was $1.3 billion. Funds were provided by net cash proceeds from the issuance of $850 million 6% senior notes ($836 million) and the issuance of $1.0 billion 4.15% senior notes ($992 million). Also, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($53 million). Funds were used for net repayments under our Credit Facility ($350 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($143 million), repurchase shares of our common stock ($17 million) and other ($14 million).

Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2013	2012	2011
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition (1)	$ 208	$ 96	$ 982
Proved Property Acquisition (2)	—	—	392
Exploration	871	572	493
Development	2,996	2,847	2,200
Corporate and Other	188	70	196
Total	$ 4,263	$ 3,585	$ 4,263
Other			
Investment in Equity Method Investee (3)	$ 48	$ 41	$ 69
Increase in Capital Lease Obligations (4)	76	—	66

(1) 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.

Unproved property acquisition cost for 2011 includes $853 million related to our acquisition of a 50% interest in Marcellus Shale undeveloped leases, $40 million related to offshore Senegal/Guinea-Bissau, $31 million related to additional acreage in the DJ Basin, and $58 million related to other onshore US lease acquisitions.

(2) Proved property acquisition in 2011 related to the Marcellus Shale asset acquisition.

(3) In connection with the Marcellus Shale joint venture, we acquired a 50% interest in CONE which is accounted for using the equity method. CONE constructs, owns and operates gathering lines and facilities related to the Marcellus Shale development.

(4) Relates to estimated construction in progress on onshore US assets in 2013 and the Aseng FSPO in 2011.

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.

Excluding the impact of the Marcellus Shale acquisition in 2011, total expenditures in 2012 increased, as compared with 2011 due to to targeted investing in our major development projects located in the DJ Basin, Marcellus Shale, offshore Equatorial Guinea and offshore Israel. In addition, exploration activity increased.

Asset Transactions In 2013, non-core asset divestitures, an acreage exchange and farm-out agreements generated cash proceeds of $327 million, as compared with $1.2 billion in 2012. In 2011, we transferred certain assets to the Ecuadorian government for cash proceeds of $73 million.

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 and natural gas. 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 2013.

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

Availability of insurance coverage, subject to customary deductibles and recovery limits, for certain perils such as war or political risk is often excluded or limited within property policies. In Israel and Equatorial Guinea, we insure against acts of war and terrorism in addition to providing insurance coverage for normal operating hazards facing our business. Additionally, as being part of critical national infrastructure, the Israel offshore and onshore assets are included in a special property coverage afforded under the Israeli government's Property Tax and Compensation Fund law; however, the amount of financial recovery through the fund is not guaranteed.

In the Gulf of Mexico, we self-insure for windstorm related exposures. 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 $800 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 $600 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 $4.5 billion (excluding capital lease and other obligations) at December 31, 2013, with maturities ranging from 2014 to 2097. Our principal source of liquidity is our Credit Facility that matures October 3, 2018. We did not engage in any short-term borrowing arrangements in 2013 or 2012 other than amounts drawn and repaid under our credit facility for working capital purposes during the normal course of business.

Credit Facility Our Credit Facility commitment is $4.0 billion through the maturity date. On October 3, 2013, we amended the Credit Facility by extending the maturity date from October 14, 2016 to October 3, 2018. 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.

At December 31, 2013, there were no borrowings outstanding under the Credit Facility, leaving $4.0 billion available for use. We expect to use the Credit Facility to fund our capital investment program, and we periodically borrow amounts for working capital purposes. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

CONSOL Installment Payments The final installment payment was paid on September 30, 2013. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Public Debt Offerings We occasionally enter into public debt offerings to increase our liquidity. 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. During 2011, we completed two underwritten public offerings of $850 million of 6% senior unsecured notes due March 1, 2041 and $1.0 billion of 4.15% senior unsecured notes due December 15, 2021. Net proceeds were used to repay outstanding indebtedness under our Credit Facility, fund our exploration and development programs and for general corporate purpose.

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 accounted for as debt. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Fixed-Rate Debt Our outstanding fixed-rate debt (excluding capital lease and other obligations) totaled approximately $4.5 billion at December 31, 2013. The weighted average interest rate on fixed-rate debt was 4.88%, with maturities ranging from 2014 to 2097. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Interest Rate Locks We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. We enter into these transactions in anticipation of public debt offerings to effectively fix the cash flows related to interest payments on the anticipated debt issuance. When the debt is issued, we settle the contracts or swap agreements and amortize remaining amounts from AOCL to interest expense over the terms of the notes. See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital increased to 35% at December 31, 2013 from 33% at December 31, 2012. Significant changes in our financial position included the following:

- $1.0 billion increase in debt due to the issuance of 5.25% notes due November 15, 2043; and
- $198 million decrease in shareholders' equity from dividends paid;

offset by:

- $328 million reduction in debt due to the final installment payment to CONSOL as well as payments under our FPSO lease obligation; and
- $978 million increase in shareholders' equity from current year net income.

Cash Interest Payments We made cash interest payments of $258 million in 2013, $259 million in 2012, and $164 million in 2011.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $51 million in 2013, $56 million in 2012, and $38 million in 2011. 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 55 cents per common share in 2013, 45 cents per common share in 2012, and 40 cents per common share in 2011 (as adjusted for the 2-for-1 stock split during the second quarter of 2013). On January 28, 2014, the Board of Directors declared a quarterly cash dividend of $0.14 per common share, which will be paid February 24, 2014 to shareholders of record on February 10, 2014. 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 250,000 shares with a total value of $14 million in 2013, 282,000 shares with a total value of $13 million in 2012, and 374,000 shares with a total value of $17 million in 2011.

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, 2013, 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.

CONSOL Carried Cost Obligation The CONSOL Carried Cost Obligation represents our agreement to fund up to approximately $2.1 billion of CONSOL's future drilling and completion costs. The CONSOL Carried Cost Obligation 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 above $4.00 per MMBtu for three consecutive months.

The CONSOL Carried Cost Obligation was suspended during 2011-2013, due to low natural gas prices. Based on the December 31, 2013 Henry Hub natural gas price strip, we forecast that the obligation could commence in March 2014, with the possibility to remain active for the duration of the year. Based on a resumption of the carry in March 2014 and our current drilling plans, the carry could total up to $225 million in 2014.

If natural gas prices were to decline again, and remain below $4.00 per MMBtu for another three consecutive month period, an active carry could revert to a suspended status.

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 liquidity or availability of or requirements for capital resources. See *Contractual Obligations* below for more information regarding off-balance sheet arrangements.

Contractual Obligations

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

Obligation	Total	2014	2015 and 2016	2017 and 2018	2019 and beyond
(millions)					
Long-Term Debt [(1)]	$ 4,484	$ 200	$ —	$ —	$ 4,284
Interest Payments [(2)]	4,604	263	522	522	3,297
Capital Lease Payments [(3)]	581	77	148	132	224
Drilling and Equipment Obligations [(4)]	427	216	211	—	—
Purchase Obligations [(5)]	273	178	93	2	—
Transportation and Gathering [(6)]	1,092	91	269	267	465
Operating Lease Obligations [(7)]	666	42	110	114	400
Other Liabilities [(8)]					
Asset Retirement Obligations [(9)]	586	39	74	158	315
Commodity Derivative Instruments [(10)]	75	65	10	—	—
Total Contractual Obligations	$ 12,788	$ 1,171	$ 1,437	$ 1,195	$ 8,985

(1) Long-term debt excludes our capital lease and other obligations. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(2) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2013. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

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

(4) Drilling and equipment obligations represent contractual agreements with third-party service providers to procure drilling rigs and other related equipment for exploratory and development drilling activities. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(5) Purchase obligations represent 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 Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(6) Transportation and gathering obligations represent minimum charges for firm transportation and gathering agreements. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

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

(8) The table excludes deferred compensation liabilities of $253 million and accrued benefit costs of $165 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

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

(10) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2013. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2013. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

As of December 31, 2013, we accrued approximately $18 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.

In addition, 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 $100 million at December 31, 2013.

Other

Income Taxes We made cash payments for income taxes, net of refunds, of $165 million in 2013, $168 million in 2012, and $288 million in 2011.

Contingencies Payments to settle legal proceedings totaled approximately $21 million in 2013, $12 million in 2012, and $1 million in 2011. 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 and natural gas 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 and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas 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 and natural gas 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, oil and gas prices are volatile and, as a result, our reserves estimates will change in the future.

Estimates of proved crude oil and natural gas reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. 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 and natural gas 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 and natural gas 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 2012 when we decided not to pursue development of our Deep Blue exploratory well in the deepwater Gulf of Mexico. Although hydrocarbons were found in both the initial exploratory well and subsequent sidetrack, we and our partners decided not to proceed with additional appraisal activities. At December 31, 2013, the balance of property, plant and equipment included $1.3 billion of suspended exploratory well costs, $733 million of which had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means including additional seismic work, drilling additional appraisal wells to confirm the size of the hydrocarbon deposit, or evaluating the potential commerciality of the exploratory wells. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs.

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

During 2013, 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 $86 million in 2013, $104 million in 2012 and $757 million in 2011 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 and natural gas 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 the years ended December 31, 2013, 2012 and 2011 and determined there were no impairments. 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 and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For 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, 2013, the consolidated balance sheet included $627 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 conduct a qualitative goodwill impairment assessment as of December 31 of each year by examining relevant events and circumstances which could have a negative impact on our goodwill such as macroeconomic conditions, industry and market conditions, 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.

After assessing the totality of events and circumstances for the qualitative impairment assessment at December 31, 2013, 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 and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer company based weighted average cost of capital.

Under the market approach, we estimate the value of the US reporting unit by comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments about the selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums. We use a peer company multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics. We use earnings before interest, taxes, DD&A and exploration expense (also known as EBITDAX) as our financial metric as 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 2013, we sold certain non-core onshore US assets. Goodwill allocated to these assets sold totaled $8 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 payable position with a fair value of $58 million at December 31, 2013. 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, 2013, we reported a $133 million mark-to-market loss on commodity derivative instruments.

We also use derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. We designate these as cash flow hedges and all changes in fair value 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 debt issuance.

In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of the instrument using the terms of the related contract. Inputs consist of published interest rate yield curves as of the date of the estimate and a measure of our own nonperformance risk, based on the current published credit default swap rates.

We compare our estimates of the fair values of our commodity and interest rate derivative instruments with those provided by our counterparties. There have been no significant differences. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk and Interest Rate Risk and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities and Note 13. Fair Value Measurements and Disclosures.

Asset Retirement Obligations Our asset retirement obligations (ARO) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of a liability for an ARO in the period in which it is incurred when we have an existing legal obligation associated with the retirement of our oil and gas properties and the obligation can reasonably be estimated. The associated asset retirement cost is capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. In periods subsequent to initial measurement of the ARO, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Revisions also result in increases or decreases in the carrying cost of the oil and gas asset. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. Asset retirement obligations totaled $586 million at December 31, 2013. See Item 8. Financial Statements and Supplementary Data – Note 9. Asset Retirement Obligations.

Income Tax Expense and Deferred Tax Assets We are subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. During 2013 and as a result 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. In 2013, we also established a valuation allowance on our available foreign tax credit carried forward of $20 million with a net increase in deferred income tax expense.

As of December 31, 2013, the accumulated undistributed earnings of our foreign subsidiaries that have been permanently reinvested totaled approximately $3.7 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.

We currently intend to use a significant portion of our international cash to fund international projects, including various exploration projects and the development of our properties in West Africa and the Eastern Mediterranean. However, we estimate that a repatriation of approximately $810 million as of December 31, 2013, if we had elected not to use the cash to fund international projects, would have had a net cash tax impact of approximately $115 million. This amount is net of estimated foreign tax credits. See Item 8. Financial Statements and Supplementary Data – Note 11. Income Taxes.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to market risk in the normal course of business operations, and the volatility of crude oil and natural gas prices continues to impact the oil and gas industry. 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, 2013, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and 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 liability position with a fair value of $58 million. Based on the December 31, 2013 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative liability by approximately $37 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative liability by approximately $10 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 8. Derivative Instruments and Hedging Activities.

Interest Rate Risk

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

At December 31, 2013, we had approximately $4.5 billion (excluding capital lease and other obligations) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 4.88%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments 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. At December 31, 2013, AOCL included $24 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified to earnings as adjustments to interest expense over the terms of our 5¼% senior notes due April 15, 2014 and 6% senior notes due March 1, 2041. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of December 31, 2013, our cash and cash equivalents totaled approximately $1.1 billion, approximately 52% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of December 31, 2013 would result in a change in annual interest income of approximately $1 million.

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. 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 transaction (gains) losses from continuing operations were de minimis for 2013 and 2012 and resulted in a loss of $8 million for 2011. The losses were primarily related to the changes in exchange rates between the US dollar and Israeli new shekel. Transaction (gains) losses are included in other (income) expense, net in the consolidated statements of operations.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

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

As of December 31, 2013, 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, 2013, 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, 2013 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, 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 6, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 6, 2014

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, 2013, 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, 2013, 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, 2013 and 2012, 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, 2013, and our report dated February 6, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 6, 2014

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

	Year Ended December 31, 2013	2012	2011
Revenues			
Oil, Gas and NGL Sales	$ 4,809	$ 4,037	$ 3,179
Income from Equity Method Investees	206	186	193
Other Revenues	—	—	32
Total Revenues	5,015	4,223	3,404
Costs and Expenses			
Production Expense	850	673	558
Exploration Expense	415	409	277
Depreciation, Depletion and Amortization	1,568	1,370	878
General and Administrative	433	384	339
Gain on Divestitures	(36)	(154)	(25)
Asset Impairments	86	104	757
Other Operating (Income) Expense, Net	43	25	86
Total Operating Expenses	3,359	2,811	2,870
Operating Income	1,656	1,412	534
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	133	(75)	(42)
Interest, Net of Amount Capitalized	158	125	65
Other Non-Operating (Income) Expense, Net	21	6	9
Total Other (Income) Expense	312	56	32
Income from Continuing Operations Before Income Taxes	1,344	1,356	502
Income Tax Provision	437	391	90
Income from Continuing Operations	907	965	412
Discontinued Operations, Net of Tax	71	62	41
Net Income	$ 978	$ 1,027	$ 453
Earnings Per Share, Basic			
Income from Continuing Operations	$ 2.53	$ 2.71	$ 1.17
Discontinued Operations, Net of Tax	0.19	0.18	0.11
Net Income	$ 2.72	$ 2.89	$ 1.28
Earnings Per Share, Diluted			
Income from Continuing Operations	$ 2.50	$ 2.68	$ 1.15
Discontinued Operations, Net of Tax	0.19	0.18	0.12
Net Income	$ 2.69	$ 2.86	$ 1.27
Weighted Average Number of Shares Outstanding			
Basic	359	356	353
Diluted	363	359	357

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

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

	Year Ended December 31,		
	2013	2012	2011
Net Income	$ 978	$ 1,027	$ 453
Other Items of Comprehensive Income (Loss)			
Interest Rate Cash Flow Hedges			
Unrealized Change in Fair Value	—	—	23
Less Tax Provision	—	—	(8)
Net Change in Pension and Other	(6)	(20)	(17)
Less Tax (Benefit)	2	7	6
Other Comprehensive Income (Loss)	(4)	(13)	4
Comprehensive Income	$ 974	$ 1,014	$ 457

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,117	$ 1,387
Accounts Receivable, Net	947	964
Other Current Assets	547	420
Total Current Assets	2,611	2,771
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	22,243	19,496
Property, Plant and Equipment, Other	517	344
Total Property, Plant and Equipment, Gross	22,760	19,840
Accumulated Depreciation, Depletion and Amortization	(7,035)	(6,289)
Total Property, Plant and Equipment, Net	15,725	13,551
Goodwill	627	635
Other Noncurrent Assets	679	597
Total Assets	$ 19,642	$ 17,554
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,354	$ 1,508
Other Current Liabilities	988	1,024
Total Current Liabilities	2,342	2,532
Long-Term Debt	4,566	3,736
Deferred Income Taxes, Noncurrent	2,441	2,218
Other Noncurrent Liabilities	1,109	810
Total Liabilities	10,458	9,296
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; 400 Million and 397 Million Shares Issued, Respectively	4	4
Additional Paid in Capital	3,463	3,302
Accumulated Other Comprehensive Loss	(117)	(113)
Treasury Stock, at Cost; 38 Million Shares	(659)	(648)
Retained Earnings	6,493	5,713
Total Shareholders' Equity	9,184	8,258
Total Liabilities and Shareholders' Equity	$ 19,642	$ 17,554

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

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

	Year Ended December 31,		
	2013	2012	2011
Cash Flows From Operating Activities			
Net Income	$ 978	$ 1,027	$ 453
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,570	1,403	965
Asset Impairments	86	104	759
Dry Hole Cost	149	182	105
Deferred Income Taxes	269	109	(81)
Dividends (Income) from Equity Method Investees, Net	(17)	7	30
Unrealized (Gain) Loss on Commodity Derivative Instruments	131	(109)	22
Gain on Divestitures	(93)	(72)	(25)
Stock Based Compensation	80	65	58
Other Adjustments for Noncash Items Included in Income	75	83	40
Changes in Operating Assets and Liabilities			
(Increase) in Accounts Receivable	(239)	(130)	(249)
(Decrease) Increase in Accounts Payable	(87)	237	3
(Decrease) Increase in Current Income Taxes Payable	(47)	64	37
Increase in Other Current Liabilities	20	18	38
Other Operating Assets and Liabilities, Net	62	(55)	15
Net Cash Provided by Operating Activities	2,937	2,933	2,170
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(3,947)	(3,650)	(2,594)
Marcellus Shale Asset Acquisition	—	—	(527)
Additions to Equity Method Investments	(48)	(41)	(69)
Proceeds from Divestitures	327	1,160	77
Other	(7)	4	—
Net Cash Used in Investing Activities	(3,675)	(2,527)	(3,113)
Cash Flows From Financing Activities			
Exercise of Stock Options	51	56	38
Excess Tax Benefits from Stock-Based Awards	20	25	15
Dividends Paid, Common Stock	(198)	(164)	(143)
Purchase of Treasury Stock	(14)	(13)	(17)
Proceeds from Credit Facilities	900	150	520
Repayment of Credit Facilities	(900)	(150)	(870)
Repayment of CONSOL Installment Loan	(328)	(328)	—
Proceeds from Issuance of Senior Long-Term Debt, Net	985	—	1,828
Settlement of Interest Rate Derivative Instrument	—	—	(40)
Repayment of Capital Lease Obligation	(48)	(45)	(3)
Other	—	(5)	(11)
Net Cash Provided By (Used in) Financing Activities	468	(474)	1,317
Increase (Decrease) in Cash and Cash Equivalents	(270)	(68)	374
Cash and Cash Equivalents at Beginning of Period	1,387	1,455	1,081
Cash and Cash Equivalents at End of Period	$ 1,117	$ 1,387	$ 1,455

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

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

	Common Stock [1]	Additional Paid in Capital [1]	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2010	$ 1,302	$ 1,734	$ (104)	$ (624)	$ 4,540	$ 6,848
Net Income	—	—	—	—	453	453
Stock-based Compensation Expense	—	58	—	—	—	58
Exercise of Stock Options	6	32	—	—	—	38
Tax Benefits Related to Exercise of Stock Options	—	15	—	—	—	15
Cash Dividends (40 cents per share)	—	—	—	—	(143)	(143)
Purchase of Treasury Stock	—	—	—	(17)	—	(17)
Rabbi Trust Shares Sold	—	6	—	3	—	9
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	—	—	15	—	—	15
Net Change in Other	4	(4)	(11)	—	—	(11)
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	(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

(1) Amounts restated to reflect impact of 2-for-1 stock split.

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

Note 1. Summary of Significant Accounting Policies

General Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide oil and gas exploration and production. Our core operating areas are onshore US (DJ Basin and Marcellus Shale), deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean.

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to US GAAP. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. See Note 7. Equity Method Investments. All significant intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

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

Other items subject to estimates and assumptions include the carrying amounts of 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. Decline in natural gas prices or a significant decline in crude oil 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 2012 and 2011 consolidated financial statements to conform to the 2013 presentation. These reclassifications were not material to the financial statements.

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

- Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.
- Level 3 measurements are fair value measurements which use unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value. See Note 13. Fair Value Measurements and Disclosures.

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

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. See Note 5. Allowance for Doubtful Accounts.

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 and natural gas 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 five to 30 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 2013, 2012, and 2011. 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 and natural gas reserves, future commodity prices and future costs to produce the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. 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 and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. 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. See Note 3. Property Transactions.

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. Acquisitions and Divestitures.

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 6. Capitalized Exploratory Well Costs.

Other Property Other property includes automobiles, trucks, airplanes, office furniture, computer equipment and other fixed assets such as buildings and leasehold improvements. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from five 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 the 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 $121 million in 2013, $151 million in 2012, and $132 million in 2011.

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 determined at current costs and is inflated into future dollars using an inflation rate that is based on the consumer price index. The future projected cash flows are then discounted to their present value using a credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense and included in our DD&A expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset. See Note 9. Asset Retirement Obligations.

Goodwill Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is 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, 2013. However, it is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

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 2013 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 unrealized 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. See Note 8. Derivative Instruments and Hedging Activities.

Stock-Based Compensation Stock options and other stock-based compensation issued to employees and directors are recorded at grant-date fair value. Expense is recognized on a straight-line basis over the employee's and director's requisite service period (generally the vesting period of the award) in the consolidated statements of operations. See Note 12. Stock-Based and Other Compensation Plans.

Pension and Other Postretirement Benefit Plans We recognize the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of our defined benefit pension, restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to AOCL, net of tax. The amount remaining in AOCL at December 31, 2013 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 12. Stock-Based and Other Compensation Plans.

Income Taxes Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax return or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted. See Note 11. Income Taxes.

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

Revenue Recognition and Imbalances We record revenues from the sales of crude oil, natural gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlements method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued.

Basic and Diluted Earnings 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 14. 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 18. Commitments and Contingencies.

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

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

Segment Information Accounting policies for geographical segments are the same as those described above. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments. See Note 15. Segment Information.

Changes in Shareholders' Equity On April 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.

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Other Revenues [1]	—	—	32
Production Expense			
Lease Operating Expense	$ 530	$ 431	$ 346
Production and Ad Valorem Taxes	188	151	146
Transportation Expense	132	91	66
Total	$ 850	$ 673	$ 558
Other Operating Expense, Net			
Deepwater Gulf of Mexico Moratorium Expense [2]	$ —	$ —	$ 18
Electricity Generation Expense [1]	—	—	26
Other, Net	43	25	42
Total	$ 43	$ 25	$ 86
Other Non-Operating (Income) Expense, Net			
Deferred Compensation Expense [3]	$ 26	$ 6	$ 8
Other (Income) Expense, Net	(5)	—	1
Total	$ 21	$ 6	$ 9

(1) Other revenues consist primarily of electricity sales from the Machala power plant, located in Machala, Ecuador, through May 2011. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation and changes in the allowance for doubtful accounts. In May 2011, we transferred our assets in Ecuador to the Ecuadorian government.

(2) Amounts relate to rig stand-by expense incurred due to the deepwater Gulf of Mexico drilling moratorium.

(3) Amounts represent increases in the fair value of shares of our common stock held in a rabbi trust.

Additional balance sheet information is as follows:

	December 31,	
(millions)	2013	2012
Accounts Receivable, Net		
Commodity Sales	$ 495	$ 349
Joint Interest Billings	382	486
Other	81	139
Allowance for Doubtful Accounts	(11)	(10)
Total	$ 947	$ 964
Other Current Assets		
Inventories, Materials and Supplies	$ 96	$ 68
Inventories, Crude Oil	25	22
Commodity Derivative Assets, Current	1	63
Deferred Income Taxes, Net, Current	62	106
Assets Held for Sale [1]	292	45
Prepaid Expenses and Other Assets, Current	71	116
Total	$ 547	$ 420
Other Noncurrent Assets		
Equity Method Investments	$ 437	$ 367
Mutual Fund Investments	114	103
Commodity Derivative Assets, Noncurrent	16	21
Other Assets, Noncurrent	112	106
Total	$ 679	$ 597
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 103	$ 113
Commodity Derivative Liabilities, Current	65	7
Income Taxes Payable	156	203
Asset Retirement Obligations, Current	39	69
Interest Payable	63	55
Current Portion of Long Term Debt [2]	200	324
Current Portion of Capital Lease and Other Obligations	58	48
Liabilities Associated with Assets Held for Sale [1]	111	12
Other Liabilities, Current	193	193
Total	$ 988	$ 1,024
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 253	$ 229
Asset Retirement Obligations, Noncurrent	547	333
Accrued Benefit Costs, Noncurrent [3]	155	116
Other Liabilities, Noncurrent	154	132
Total	$ 1,109	$ 810

[1] Assets held for sale consist primarily of oil and gas properties and liabilities associated with asset retirement obligations located in China, the North Sea and onshore US at December 31, 2013 and the North Sea at December 31, 2012. See Note 3. Property Transactions.

[2] See Note 10. Long-Term Debt.

[3] Amount includes liabilities accrued under our defined benefit pension plan, restoration plan, and other postretirement benefit plans. See Note 12. Stock-Based and Other Compensation Plans.

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 137	$ 107	$ 32
Income Taxes Paid, Net	165	168	288
Non-Cash Financing and Investing Activities			
Increase in CONSOL Installment Payments, Net of Discount (1)	—	—	639
Increase in Capital Lease and Other Obligations (1)	96	—	66

(1) See Note 3. Property Transactions and Note 10. Long-Term Debt.

Note 3. Property Transactions

Sale of North Sea Properties During 2013, we closed three sales of non-operated working interest properties located in the North Sea. The sales resulted in a $65 million gain based on net sales proceeds of $56 million for the fields.

During 2012, we closed the sale of our 30% non-operated working interest in the Dumbarton and Lochranza fields located in the North Sea. Proceeds from the transaction were $117 million and included final closing adjustments from the effective date of January 1, 2012. The net book value of assets sold was $255 million. Asset retirement obligations associated with the sale were $55 million. We reversed a deferred tax liability and recognized a corresponding income tax benefit of $99 million related to the sale.

As of December 31, 2013, all the properties remaining in our North Sea geographical segment are included in assets held for sale in our consolidated balance sheet. Our consolidated statements of operations have been reclassified for all periods presented to reflect the operations of our North Sea geographical segment as discontinued.

Included in income before income taxes during 2012, below, is exploratory expense of $27 million related to our Selkirk field. During the fourth quarter of 2012, the nearby Bligh well, a potential co-development candidate for Selkirk, was drilled. Bligh encountered noncommercial quantities of hydrocarbons; therefore, we determined that Selkirk was uneconomic for joint development.

Upon reclassification as held for sale, depreciation, depletion, and amortization (DD&A) ceased for the North Sea segment. Our long-term debt is recorded at the consolidated level; therefore no interest expense has been allocated to discontinued operations.

Summarized results of discontinued operations are as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Oil and Gas Sales	$ 37	$ 208	$ 357
Income Before Income Taxes	12	101	215
Income Tax Expense	6	55	174
Operating Income, Net of Tax	6	46	41
Gain on Sale, Net of Tax	65	16	—
Discontinued Operations, Net of Tax	$ 71	$ 62	$ 41

Sale of Onshore US Properties During 2013 and 2012, we closed the sales of non-core onshore US crude oil and natural gas properties. The information regarding the assets sold is as follows:

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

We continue to market non-core onshore US properties; certain of these assets met the criteria for reclassification as assets held for sale at December 31, 2013.

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 consolidates our acreage into large contiguous blocks, which will provide the opportunity to optimize drilling, production, and gathering activities and add more extended-reach lateral wells to our development program.These opportunities provide efficiencies by owning and operating properties located within a smaller geographical area, with the potential to significantly enhance field economics. 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.

Marcellus Shale Joint Venture On September 30, 2011, we closed an agreement with a subsidiary of CONSOL Energy Inc. (CONSOL) for the development of Marcellus Shale properties in southwest Pennsylvania and northwest West Virginia. Under the agreement, we acquired a 50% interest in approximately 628,000 net undeveloped acres, certain producing properties, and existing infrastructure, such as pipeline and gathering facilities, for approximately $1.3 billion, including post-closing adjustments. We and CONSOL also formed CONE Gathering LLC (CONE) to own and operate the existing and future infrastructure. We paid the final installment payment of $328 million as of December 31, 2013. See Note 10. Long-Term Debt.

As part of the joint venture transaction, 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, up to approximately $2.1 billion (CONSOL Carried Cost Obligation), which is expected to be paid out over a multi-year period. 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 will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The CONSOL Carried Cost Obligation was suspended during 2011 - 2013 due to low natural gas prices.

The final purchase price allocation resulted in the following:

(millions)	December 31, 2012
Unproved Oil and Gas Properties	$ 803
Proved Oil and Gas Properties	386
Investment in CONE Gathering LLC	69
Total Assets Acquired [1]	$ 1,258

[1] Total reflects impact of $17 million imputed interest on CONSOL installment payments.

We used an income approach to estimate the fair value of the proved oil and gas properties as of the acquisition date. We utilized a discounted cash flow model which took into account the following inputs to arrive at estimates of future net cash flows:

- estimated quantities of crude oil and natural gas reserves prepared by our qualified petroleum engineers;
- management's estimates of future commodity prices based on NYMEX Henry Hub natural gas futures prices and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar properties which we operate.

We discounted the resulting future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. The fair value of the proved producing properties is considered a Level 3 fair value measurement.

Exit from Ecuador In May 2011, we transferred our assets in Ecuador to the Ecuadorian government. We received cash proceeds of $73 million for the transfer of our offshore Amistad field assets, onshore gas processing facilities and Block 3 PSC and the assignment of the Machala Power electricity concession and its associated assets. Our net book value for the assets had been reduced due to previous impairment charges, resulting in a pre-tax gain of $25 million.

Note 4. Asset Impairments

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Piceance (Onshore US)	$ —	$ 39	$ 487
South Raton (Deepwater Gulf of Mexico)	—	34	—
Mari-B (Offshore Israel)	47	31	—
Other Onshore US Properties	39	—	270
Total	$ 86	$ 104	$ 757

2013 Asset Impairments We recorded impairments of the Mari-B field, due to natural field decline, and certain non-core, onshore US properties upon reclassification to assets held for sale. The Mari-B field was written down to its estimated fair value using a discounted cash flow model which included management's estimates of future oil and 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. 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 our Piceance development, onshore US, and declines in near-term crude oil prices associated with our South Raton development in the deepwater Gulf of Mexico, 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 of our Mari-B, Noa and Pinnacles fields, 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 discounted cash flow models, as described above.

2011 Asset Impairments Due to a significant decline in spot and five-year forward natural gas prices, specifically during the fourth quarter of 2011, as well as field performance, we determined that the carrying amounts of certain of our onshore US assets were not recoverable from future cash flows and, therefore, were impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models, as described above.

See also Note 13. Fair Value Measurements and Disclosures.

Note 5. Allowance for Doubtful Accounts

Changes in the allowance for doubtful accounts were as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Balance, Beginning of Period	$ 10	$ 9	$ 27
Changes			
Changes in Ecuador Receivable, Net[1]	—	—	(19)
Other Changes	1	1	1
Net Changes	1	1	(18)
Balance, End of Period	$ 11	$ 10	$ 9

(1) During 2011, recovery of approximately $19 million for outstanding receivables was included in the final terms of our agreement to transfer our assets and the associated electricity concession and PSC to the Ecuadorian government. See Note 3. Property Transactions.

Note 6. Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense as dry hole cost.

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Capitalized Exploratory Well Costs, Beginning of Period	$ 900	$ 696	$ 466
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	581	360	322
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves [1]	(177)	(18)	(55)
Capitalized Exploratory Well Costs Charged to Expense [2]	(3)	(114)	(37)
Other [3]	—	(24)	—
Capitalized Exploratory Well Costs, End of Period	$ 1,301	$ 900	$ 696

(1) The 2013 amount relates primarily to Gunflint (deepwater Gulf of Mexico), for which we sanctioned a development plan.

(2) The 2012 amount primarily represents Deep Blue (deepwater Gulf of Mexico) exploratory well costs capitalized prior to December 31, 2012.

(3) The 2012 amount relates to Selkirk (North Sea) exploratory well costs capitalized prior to December 31, 2012. 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)	2013	2012	2011
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 568	$ 355	$ 318
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	733	545	378
Balance at End of Period	$ 1,301	$ 900	$ 696
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	13	14	13

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of December 31, 2013:

(millions)	Total	Suspended Since 2011 - 2012	Suspended Since 2009 - 2010	Suspended Since 2008 & Prior	Progress
Country/Project:					
Offshore Equatorial Guinea					
Diega (including Carmen)	$ 108	$ 43	$ 23	$ 42	We are evaluating regional development scenarios for this 2008 crude oil discovery
Carla	44	44	—	—	We are evaluating regional development scenarios for this 2011 crude oil discovery
Felicita	37	2	6	29	We are evaluating regional development plans for this 2008 condensate and natural gas discovery
Yolanda	19	1	3	15	We are evaluating regional development plans for this 2007 condensate and natural gas discovery
Offshore Cameroon					
YoYo	47	5	8	34	We are working with the government to assess commercialization of this 2007 condensate and natural gas discovery
Offshore Israel					
Leviathan	144	97	47	—	We are evaluating both domestic and export development concepts for this 2010 natural gas discovery
Leviathan-1 Deep	73	73	—	—	The well did not reach the target interval; we are developing future drilling plans to test this deep oil concept
Dalit	24	1	23	—	We have submitted a development plan to the government to develop this 2009 natural gas discovery as a tie-in to existing infrastructure
Tanin 1	34	34	—	—	We are reviewing regional development scenarios for this 2011 natural gas discovery
Dolphin 1	23	23	—	—	We are reviewing regional development scenarios for this 2011 natural gas discovery
Offshore Cyprus					
Cyprus A-1	74	74	—	—	We are continuing to drill and evaluate appraisal wells for this 2011 natural gas discovery
Falkland Islands					
Scotia	72	72	—	—	We are evaluating future appraisal well locations and are in the process of acquiring seismic data
Other					
Projects less than $10 million	34	29	5	—	We are continuing to drill and evaluate appraisal wells
Total	$ 733	$ 498	$ 115	$ 120	

Note 7. Equity Method Investments

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; and
- 50% interest in CONE Gathering LLC (CONE), which owns and operates natural gas gathering facilities servicing our joint venture properties in the Marcellus Shale.

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. At December 31, 2013, our retained earnings included $105 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $9 million higher than the underlying net assets of the investee at December 31, 2013. The difference is related to capitalized interest which is being amortized into earnings over the remaining useful life of the plant.

Equity method investments are as follows:

	December 31,	
(millions)	2013	2012
Equity Method Investments		
AMPCO	$ 139	$ 137
Alba Plant	95	93
CONE	184	121
Other	19	16
Total Equity Method Investments	$ 437	$ 367

Summarized, 100% combined financial information for equity method investees is as follows:

	December 31,	
(millions)	2013	2012
Balance Sheet Information		
Current Assets	$ 463	$ 384
Noncurrent Assets	983	902
Current Liabilities	373	348
Noncurrent Liabilities	29	24

	Year Ended December 31,		
(millions)	2013	2012	2011
Statements of Operations Information			
Operating Revenues	$ 1,256	$ 1,173	$ 1,139
Operating Expenses	388	361	335
Operating Income	868	812	804
Other (Income) Net	(14)	(5)	(12)
Income Before Income Taxes	882	817	816
Income Tax Provision	212	200	201
Net Income	$ 670	$ 617	$ 615

Note 8. Derivative Instruments and Hedging Activities.

Objective and Strategies for Using Derivative Instruments In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements 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, 2013.

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.

See Note 13. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk.

Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated March 2011 debt issuance. During first quarter 2011, the net liability position on the swap was reduced in our mark to market calculation, and we recognized a corresponding gain of $23 million, net of tax, in AOCL. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million at the time of settlement. Approximately $26 million, net of tax, was recorded in accumulated other comprehensive loss (AOCL) and is being reclassified to interest expense over the term of the notes. The ineffective portion of the interest rate swap was de minimis.

Unsettled Derivative Instruments As of December 31, 2013, we had entered into the following crude oil derivative instruments:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of December 31, 2013							
2014	Swaps	NYMEX WTI	37,000	$ 92.67	$ —	$ —	$ —
2014	Swaps	Dated Brent	13,000	103.21	—	—	—
2014	Three-Way Collars	NYMEX WTI	12,000	—	75.67	90.67	100.88
2014	Three-Way Collars	Dated Brent	8,000	—	84.38	98.25	121.56
2015	Swaps	NYMEX WTI	16,000	87.66	—	—	—
2015	Swaps	Dated Brent	8,000	100.20	—	—	—
2015	Three-Way Collars	NYMEX WTI	15,000	—	70.67	88.00	94.78
2015	Three-Way Collars	Dated Brent	11,000	—	76.36	95.27	109.26

As of December 31, 2013, we had entered into the following natural gas derivative instruments:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of December 31, 2013							
2014	Swaps	NYMEX HH	60,000	$ 4.24	$ —	$ —	$ —
2014	Three-Way Collars	NYMEX HH	230,000	—	2.83	3.75	4.98
2015	Swaps	NYMEX HH	80,000	4.32	—	—	—
2015	Three-Way Collars	NYMEX HH	120,000	—	3.54	4.25	5.06

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, 2013		December 31, 2012		December 31, 2013		December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)								
Commodity Derivative Instruments	Current Assets	$ 1	Current Assets	$ 63	Current Liabilities	$ 65	Current Liabilities	$ 7
	Noncurrent Assets	16	Noncurrent Assets	21	Noncurrent Liabilities	10	Noncurrent Liabilities	3
Total		$ 17		$ 84		$ 75		$ 10

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Realized Mark-to-Market (Gain) Loss [(1)]			
Crude Oil	$ 52	$ 83	$ 44
Natural Gas	(50)	(49)	(108)
Total Realized Mark-to-Market (Gain) Loss	2	34	(64)
Unrealized Mark-to-Market (Gain) Loss [(1)]			
Crude Oil	87	(120)	5
Natural Gas	44	11	17
Total Unrealized Mark-to-Market (Gain) Loss	131	(109)	22
Total (Gain) Loss on Commodity Derivative Instruments	$ 133	$ (75)	$ (42)

(1) Gains and losses on commodity derivative instruments included in net income include both pre-tax realized gains and losses, which equals the cash settlements during the period, and pre-tax, unrealized, non-cash gains or losses, which are due to the change in the mark-to-market value of our commodity contracts. Many factors impact our gain and loss on commodity derivative instruments including: increases and decreases in the commodity forward curves compared to our executed hedging arrangements; increases and decreases in hedged future volumes; and the mix of hedge arrangements between NYMEX WTI, Dated Brent and NYMEX HH commodities. Unrealized mark-to-market gains or losses recognized in the current period will be realized in the future when cash settlement occurs.

Derivative Instruments in Cash Flow Hedge Relationships

	Amount of (Gain) Loss on Derivative Instruments Recognized in Other Comprehensive (Income) Loss			Amount of (Gain) Loss on Derivative Instruments Reclassified from Accumulated Other Comprehensive (Income) Loss		
(millions)	2013	2012	2011	2013	2012	2011
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	$ —	$ —	$ (23)	$ 1	$ 1	$ 1
Total	—	—	(23)	1	1	1

AOCL at December 31, 2013 included deferred losses of $24 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 April 2014 and March 2041. Approximately $1 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 9. Asset Retirement Obligations

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

	Year Ended December 31,	
(millions)	2013	2012
Asset Retirement Obligations, Beginning Balance	$ 402	$ 377
Liabilities Incurred	90	43
Liabilities Settled	(41)	(112)
Revision of Estimate	156	102
Accretion Expense	28	22
Other	(49)	(30)
Asset Retirement Obligations, Ending Balance	$ 586	$ 402

For the year ended December 31, 2013

Liabilities incurred were due to new wells and facilities and included $68 million for deepwater Gulf of Mexico, $15 million for onshore US development, 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.

For the year ended December 31, 2012

Liabilities incurred were due to new wells and facilities and included $6 million for onshore US development, $8 million for deepwater Gulf of Mexico, and $29 million for offshore Israel.

Liabilities settled primarily included $20 million related to non-core, onshore US assets sold, $55 million related to North Sea assets sold, and $34 million related to the Leviathan-2 appraisal well, offshore Israel.

Revisions were due to changes in estimated costs for future abandonment activities and included $54 million for onshore US, $6 million for deepwater Gulf of Mexico, $26 million for offshore Israel, and $16 million for offshore China.

Other includes North Sea 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 10. Long-Term Debt

Our debt consists of the following:

	December 31, 2013			December 31, 2012		
(millions, except percentages)		Debt	Interest Rate		Debt	Interest Rate
Credit Facility, due October 3, 2018 [1]	$	—	—	$	—	—
CONSOL Installment Payment		—	—		328	1.79% [2]
Capital Lease and Other Obligations		359	—		311	—
5¼% Senior Notes, due April 15, 2014		200	5.25%		200	5.25%
8¼% 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%
7¼% Senior Notes, due October 15, 2023		100	7.25%		100	7.25%
8% Senior Notes, due April 1, 2027		250	8.00%		250	8.00%
6% Senior Notes, due March 1, 2041		850	6.00%		850	6.00%
5¼% Senior Notes, due November 15, 2043		1,000	5.25%		—	—
7¼% Senior Debentures, due August 1, 2097		84	7.25%		84	7.25%
Total		4,843			4,123	
Unamortized Discount		(19)			(15)	
Total Debt, Net of Discount		4,824			4,108	
Less Amounts Due Within One Year						
Current Portion of Long Term Debt, net of discount		(200)			(324)	
Capital Lease and Other Obligations		(58)			(48)	
Long-Term Debt Due After One Year	$	4,566		$	3,736	

(1) Our Credit Agreement provides for a $4.0 billion Credit Facility. The Credit Facility is available for general corporate purposes.
(2) Imputed rate based on the prevailing market rates for similar debt instruments at the date of assessment.

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 $41 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 bank unsecured revolving credit facility (Credit Facility) to extend the maturity date to October 3, 2018.

The 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, 2013, 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.

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.

CONSOL Installment Payments On September 30, 2011, we closed an agreement with CONSOL for the development of Marcellus Shale properties. In addition to the cash paid at closing, we agreed to make two installment payments of $328 million each, the first of which was paid on September 30, 2012. The second installment payment was paid on September 30, 2013. See Note 3. Property Transactions and Note 13. Fair Value Measurements and Disclosures.

Capital Lease and Other Obligations The amounts of the capital lease obligations are based on the discounted present value of future minimum lease payments, and therefore do not reflect future cash lease payments. Amounts due within one year equal the amount by which the capital lease obligations are expected to be reduced during the next 12 months. See Note 18. Commitments and Contingencies for future capital lease payments.

Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments, are as follows:

(millions)	Debt Principal Payments
December 31, 2013	
2014	$ 200
2015	—
2016	—
2017	—
2018	—
Thereafter	4,284
Total	$ 4,484

Note 11. Income Taxes

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Domestic	$ 202	$ 92	$ (537)
Foreign	1,142	1,264	1,039
Total	$ 1,344	$ 1,356	$ 502

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

	Year Ended December 31,		
(millions)	2013	2012	2011
Current Taxes			
Federal	$ 21	$ 14	$ 11
State	1	1	2
Foreign	144	143	155
Total Current	166	158	168
Deferred Taxes			
Federal	96	60	(130)
State	1	1	(3)
Foreign	174	172	55
Total Deferred	271	233	(78)
Total Income Tax Provision	$ 437	$ 391	$ 90
Effective Tax Rate	32.5%	28.8%	17.9%

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

	Year Ended December 31,		
(percentages)	2013	2012	2011
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	(5.3)	(4.9)	(13.3)
State Taxes, Net of Federal Benefit	0.1	0.2	(0.1)
Difference Between US and Foreign Rates	(6.3)	(4.9)	(7.0)
Foreign Exploration Loss	2.7	(3.8)	(4.2)
Change in Valuation Allowance	3.8	4.3	6.6
Oil Profits Tax - Israel	0.3	0.9	2.6
Tax Contingency	0.4	1.8	—
Other, Net	1.8	0.2	(1.7)
Effective Rate	32.5	28.8	17.9

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(millions)	2013	2012
Deferred Tax Assets		
Loss Carryforwards	$ 174	$ 235
Employee Compensation & Benefits	143	134
Foreign Tax Credits	31	38
Other	56	81
Total Deferred Tax Assets	404	488
Valuation Allowance - Foreign Loss Carryforwards	(135)	(81)
Valuation Allowance - Foreign Tax Credits	(31)	(38)
Valuation Allowance - Capital Loss Carryforwards	(2)	—
Net Deferred Tax Assets	236	369
Deferred Tax Liabilities		
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,615)	(2,481)
Total Deferred Tax Liability	(2,615)	(2,481)
Net Deferred Tax Liability	$ (2,379)	$ (2,112)

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

	December 31,	
(millions)	2013	2012
Deferred Income Tax Asset - Current	$ 62	$ 106
Deferred Income Tax Liability - Noncurrent	(2,441)	(2,218)
Net Deferred Tax Liability	$ (2,379)	$ (2,112)

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, 2013. 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 $135 million in 2013, $81 million in 2012, and $65 million in 2011. 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 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.

During 2012, as a result of execution of tax planning strategies, we reversed a $57 million deferred tax asset for future foreign tax credits from our foreign branch operations along with the corresponding valuation allowance. Additionally, we recorded a $38 million valuation allowance on excess foreign tax credits and released $12 million of deferred tax liability for a net increase in deferred income tax expense.

Effective Tax Rate 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.

Our effective tax rate increased in 2012 as compared with 2011, primarily due to reduced impact of equity method earnings, which had the effect of decreasing the 2011 rate. The rate also increased due to additional valuation allowances and nondeductible allocation of goodwill to assets sold in 2012.

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, 2013, the accumulated undistributed earnings of the foreign subsidiaries that have been permanently reinvested were approximately $3.7 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. 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 $700 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: U.S. - 2010, Equatorial Guinea - 2008, Israel - 2009, and China - 2010.

Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. However, we did not accrue penalties at December 31, 2012 or 2011, because we believe that we are below the minimum statutory threshold for imposition of penalties.

A reconciliation of our beginning and ending amounts of unrecognized tax benefits follows:

(millions)	Twelve Months Ended December 31, 2013
Unrecognized Tax Benefits, Beginning Balance	$ 23
Additions for tax positions related to current year	—
Additions for tax positions of prior years	7
Reductions for tax positions of prior years	(2)
Settlements	—
Unrecognized Tax Benefits, Ending Balance	$ 28

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 12. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
(millions)	2013	2012	2011
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 58	$ 48	$ 42
Exploration Expense and Other	22	17	16
Total Stock-Based Compensation Expense	$ 80	$ 65	$ 58
Tax Benefit Recognized	$ (28)	$ (23)	$ (20)

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 award restricted stock to our officers or other employees and those of our subsidiaries. At December 31, 2013, 35,652,195 shares of our common stock were reserved for issuance, including 18,549,928 shares available for future grants and awards, under the 1992 Plan.

Stock options are issued with an exercise price equal to the market price 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 ten years 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 Restricted Period, 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. 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 remaining 60% after year two). Restricted stock awards with a market based 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. (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. The total number of shares of our common stock that may be issued under the 2005 Plan is 1,600,000. At December 31, 2013, 1,376,644 shares of our common stock were reserved for issuance, including 893,820 shares available for future grants and awards under the 2005 Plan.

The 2005 Plan provides for the granting to a non-employee director of up to a maximum of 22,400 stock options on the date of election to the Board of Directors, annual grants of 5,600 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 22,400 options). 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. The options expire ten years from the date of grant.

The 2005 Plan also provides for the awarding to a non-employee director of up to a maximum of 9,600 shares of restricted stock on the date of election to the Board of Directors, annual awards of 2,400 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 9,600 shares of restricted stock). 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 ten 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)	2013	2012	2011
Expected Term (in Years)	5.7	5.7	5.7
Expected Volatility	36.4%	37.0%	36.2%
Risk-Free Rate	1.1%	0.9%	2.2%
Expected Dividend Yield	1.2%	1.2%	1.1%
Weighted Average Grant-Date Fair Value	$ 17.08	$ 15.99	$ 15.09

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, 2012	12,411,572	$ 35.14		
Granted	2,492,855	54.64		
Exercised	(1,892,962)	27.05		
Forfeited	(333,608)	51.99		
Outstanding at December 31, 2013	12,677,857	$ 39.82	6.2	$ 359
Exercisable at December 31, 2013	8,383,018	$ 33.53	5.0	$ 290

The total intrinsic value of options exercised was $64 million in 2013, $72 million in 2012, and $40 million in 2011.

As of December 31, 2013, $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, 2013
Number of Simulations	500,000
Expected Volatility	30%
Risk-Free Rate	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	Number of Shares	Weighted Average Award Date Fair Value
		(per share)		*(per share)*
Outstanding at December 31, 2012	1,866,462	$ 46.40	—	$ —
Awarded	485,587	54.81	891,504	28.96
Vested	(781,838)	43.04	—	—
Forfeited	(82,342)	50.04	(43,478)	28.65
Outstanding at December 31, 2013	1,487,869	$ 50.74	848,026	$ 28.93

The total fair value of restricted stock that vested was $43 million in 2013, $47 million in 2012, and $57 million in 2011.

The weighted average award-date fair value of restricted stock awarded was $38.07 per share in 2013, $50.75 per share in 2012, and $45.16 per share in 2011.

As of December 31, 2013, $47 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. 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 $21 million in 2013, $17 million in 2012, and $14 million in 2011.

As a result of the termination of the retirement and restoration plans (see below), employees who were hired prior to May 1, 2006 will become eligible to receive profit sharing contributions effective January 1, 2014. In addition, certain of these employees will also be eligible to receive transition contributions related to the termination of the plans.

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 may elect to receive distributions in either cash or shares of our common stock. Components of the rabbi trust are as follows:

	December 31,	
(millions, except share amounts)	2013	2012
Rabbi Trust Assets		
Mutual Fund Investments	$ 88	$ 84
Noble Energy Common Stock (at Fair Value)	88	76
Total Rabbi Trust Assets	176	160
Liability Under Related Deferred Compensation Plan	$ 176	$ 160
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	1,292,335	1,493,343

Assets of the rabbi trust, other than our common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds have published market prices and are reported at fair value. See Note 13. Fair Value Measurements and Disclosures. The mutual funds are included in the mutual fund investments account in other noncurrent assets in the consolidated balance sheets.

Shares of our common stock held by the rabbi trust 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 1,200,000 shares, or 93%, of our common stock held in the plan at December 31, 2013 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next six years. Distributions of 200,000 shares were made in each of 2013 and 2012. In addition, plan participants sold 1,008 shares of our common stock in 2013, 4,536 shares in 2012, and 200 shares in 2011. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $25 million in 2013, $19 million in 2012 and $17 million in 2011.

All fluctuations in market value of the deferred compensation liability have been reflected in other non-operating (income) expense, net in the consolidated statements of operations. We recognized deferred compensation expense of $26 million in 2013, $6 million in 2012 and $8 million in 2011.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. Deferred compensation liabilities of $77 million, $70 million and $60 million were outstanding at December 31, 2013, 2012 and 2011, respectively, under the unfunded plan.

Pension and Other Postretirement Benefit Plans We have a noncontributory, tax-qualified defined benefit 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 sponsor other plans, which include medical and life insurance benefits, for the benefit of our employees and retirees.

During the fourth quarter of 2013, we notified the Retirement Plan participants that, effective December 31, 2013: Retirement Plan benefit accruals will cease and the Retirement Plans will be frozen; and certain plan amendments were adopted related to final average earnings, age 55 subsidies and a lump sum rate change related to this notification. We will begin the process of securing approval from the Pension Benefit Guaranty Corporation and IRS to liquidate the related Retirement Trust and complete the Retirement Plan termination. The Retirement Plan participants will continue to receive benefits until the Retirement Trust is liquidated, primarily through lump-sum payments to participants, and this process could take up to two years to complete. The restoration plan will also be terminated.

As a result of the cessation of accrual of additional Retirement Plan benefits earned, a plan curtailment has been triggered. Moreover, the work force has been reduced or the accrual of benefits for some or all future services has been eliminated, and the Company will not realize all the expected future economic benefits of the plan amendments being amortized as prior service cost over the expected remaining service lives of the participants. Consequently, the unamortized prior service cost of $2 million relating to the Retirement Plan participants affected was expensed as of December 31, 2013. We reduced the pension benefit obligation by approximately $33 million to omit the impact of expected future salary increases due to the plan freeze. This reduction in the benefit obligation from the curtailment resulted in a gain, which was offset by existing unamortized net loss recorded in AOCL.

Regarding the plan amendments, we recorded an increase in the plan benefit obligation and new prior service cost of approximately $88 million. The new prior service costs included in AOCL will be amortized consistent with our amortization policy. Upon plan termination, all remaining unamortized prior service cost and net actuarial loss will be charged to expense.

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)	2013	2012	2013	2012
Pension Benefit Obligation	$ (394)	$ (343)	$ (36)	$ (27)
Fair Value of Plan Assets	265	247	—	—
Net Amount Recognized in Consolidated Balance Sheet	(129)	(96)	(36)	(27)
Noncurrent Liabilities	(123)	(90)	(34)	(26)
Net Prior Service (Cost) Credit, Before Tax	$ (88)	$ (2)	$ 6	$ 8
Net Gains (Losses), Before Tax	(56)	(133)	(15)	(12)
Accumulated Other Comprehensive Income (Loss)	$ (144)	$ (135)	$ (9)	$ (4)

At December 31, 2013, plan assets were invested primarily in cash and fixed-income securities. We expect to make additional contributions to the pension and restoration plans during the next 12 to 24 months to the extent necessary to fund remaining benefit obligations.

Net periodic benefit cost related to these plans totaled $37 million in 2013, $27 million in 2012, and $21 million in 2011.

Note 13. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance 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 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 (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 8. Derivative Instruments and Hedging Activities.

Deferred Compensation Liability The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See *Mutual Fund Investments* above.

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

(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, 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)
December 31, 2012					
Financial Assets					
Mutual Fund Investments	$ 103	$ —	$ —	$ —	$ 103
Commodity Derivative Instruments	—	113	—	(29)	84
Financial Liabilities					
Commodity Derivative Instruments	—	(39)	—	29	(10)
Portion of Deferred Compensation Liability Measured at Fair Value	(160)	—	—	—	(160)

(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, 2013					
Impaired Oil and Gas Properties	$ —	$ —	$ 113	$ 199	$ 86
Year Ended December 31, 2012					
Impaired Oil and Gas Properties	—	—	228	332	104
Year Ended December 31, 2011					
Impaired Oil and Gas Properties	—	—	213	970	757

(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 oil and gas production, commodity prices based on sales contract terms or NYMEX 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.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public fixed rate debt to be a Level 1 measurement on the fair value hierarchy. The carrying amounts of the CONSOL installment payment at December 31, 2012 approximated fair value because it had been discounted at the prevailing market rate for similar debt instruments. As such, we considered the fair value of our CONSOL installment payment to be a Level 2 measurement on the fair value hierarchy. See Note 10. Long-Term Debt. Fair value information regarding our debt is as follows:

	December 31, 2013		December 31, 2012	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net of Unamortized Discount [1]	$ 4,465	$ 4,959	$ 3,797	$ 4,570

[1] Excludes capital lease and other obligations. No floating rate debt was outstanding at December 31, 2013 or December 31, 2012. See Note 10. Long-Term Debt.

Note 14. 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)	2013	2012	2011
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$ 907	$ 965	$ 412
Weighted Average Number of Shares Outstanding, Basic	359	356	353
Incremental Shares From Assumed Conversion of Dilutive Stock Options and Restricted Stock	4	3	4
Weighted Average Number of Shares Outstanding, Diluted	363	359	357
Earnings from Continuing Operations Per Share, Basic	**$ 2.53**	**$ 2.71**	**$ 1.17**
Earnings from Continuing Operations Per Share, Diluted	**2.50**	**2.68**	**1.15**

Additional Information			
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	5	4
Weighted average option exercise price per share	$ 53.40	$ 48.73	$ 42.70

Note 15. Segment Information

We have operations throughout the world and manage our operations by region. The following information is grouped into four components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Sierra Leone, and Senegal/Guinea-Bissau (which we exited in 2012); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes China, Ecuador (through May 2011), Falkland Islands, Nicaragua and new ventures. As of December 31, 2013, the remaining North Sea assets were reclassified to assets held for sale; prior year amounts have been reclassified to exclude the North Sea geographical segment from continuing operations. See Note 3. Property Transactions.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
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)	—	—	—
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)	—	—	—
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
Year Ended December 31, 2011					
Revenues from Third Parties [1]	$ 3,211	$ 2,125	$ 592	$ 307	$ 187
Income from Equity Method Investees	193	—	193	—	—
Total Revenues	3,404	2,125	785	307	187
DD&A	878	732	69	25	52
Asset Impairments	757	757	—	—	—
Gain on Divestitures	(25)	—	—	—	(25)
Income (Loss) from Continuing Operations Before Income Taxes	502	96	561	228	(383)
Equity Method Investments	329	72	257	—	—
Additions to Long-Lived Assets	4,358	3,007	618	687	46
Goodwill at End of Year	696	696	—	—	—
Total Assets at End of Year [2]	16,105	11,201	2,728	1,751	425

[1] Revenues from third parties for all foreign countries, in total, were $1.8 billion in 2013, $1.7 billion in 2012, and $1.1 billion in 2011.

[2] Long-lived assets located in all foreign countries, in total, were $4.5 billion, $4.2 billion, and $3.2 billion at December 31, 2013, 2012, and 2011, respectively.

Note 16. Concentration of Risk

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

	Percentage of Crude Oil Sales	Percentage of Total Oil, Gas & NGL Sales
Year Ended December 31, 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%
Year Ended December 31, 2011		
Glencore Energy UK Ltd	24%	16%
Shell [(1)]	17%	12%

(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, such as Leviathan, offshore Israel, 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. See Note 5. Allowance for Doubtful Accounts.

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 hedging counterparties, and our internal hedge policies provide for mark-to-market exposure limits. We use master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be “net settled” at the time of election.

Note 17. Additional Shareholders' Equity Information

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

	Year Ended December 31,	
	2013	2012
Common Stock Shares Issued		
Shares, Beginning of Period	396,697,484	393,313,692
Exercise of Common Stock Options	1,892,962	2,530,462
Restricted Stock Awards, Net of Forfeitures	1,251,271	853,330
Shares, End of Period	399,841,717	396,697,484
Treasury Stock		
Shares, Beginning of Period	37,550,752	37,473,040
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	250,307	282,248
Rabbi Trust Shares Distributed and/or Sold	(201,008)	(204,536)
Shares, End of Period	37,600,051	37,550,752

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, 2010	$ (42)	$ (62)	$ (104)
Realized Amounts Reclassified Into Earnings	1	4	5
Unrealized Change in Fair Value	15	(16)	(1)
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)

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

Note 18. Commitments and Contingencies

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

CONSOL Carried Cost Obligation Based on the December 31, 2013 Henry Hub natural gas price strip, and our current development plan, we forecast our CONSOL Carried Cost Obligation may commence in March 2014.

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 $50 million in 2013, $37 million in 2012, and $31 million in 2011.

Minimum commitments as of December 31, 2013 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering	Operating Lease Obligations	Capital Lease Payments[1]	Total
2014	$ 394	$ 91	$ 42	$ 77	$ 604
2015	201	134	49	82	466
2016	103	135	61	66	365
2017	2	134	61	66	263
2018	—	133	53	66	252
2019 and Thereafter	—	465	400	224	1,089
Total	$ 700	$ 1,092	$ 666	$ 581	$ 3,039

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 10. Long-Term Debt.

In accordance with US GAAP for disclosures about oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures about our crude oil and natural gas reserves and exploration and production activities.

Reserves

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas 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 and natural gas that are ultimately recovered.

Economic producibility of reserves is dependent on the crude oil and natural gas prices used in the reserves estimate. We based our December 31, 2013, 2012, and 2011 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 or natural gas 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, 2013. 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, Equatorial Guinea, Israel and Other International. Other International includes Cameroon, China, Cyprus, Falkland Islands, North Sea, Nicaragua, Sierra Leone, Senegal/Guinea-Bissau (through 2011) and other new ventures. The North Sea geographical segment is classified as discontinued operations in our consolidated financial statements.

Operations in China, Cyprus, Equatorial Guinea, 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.

Undeveloped Oil and Gas Reserves Proved undeveloped oil and gas reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

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

	Crude Oil, Condensate and NGLs (MMBbls)			
	United States [1]	Equatorial Guinea	Other Int'l [2]	Total
Proved Reserves as of:				
December 31, 2010	225	112	28	365
Revisions of Previous Estimates [3]	(5)	2	(6)	(9)
Extensions, Discoveries and Other Additions [4]	43	—	2	45
Purchase of Minerals in Place [5]	—	—	—	—
Sale of Minerals in Place [6]	—	—	—	—
Production [7]	(19)	(8)	(5)	(32)
December 31, 2011	244	106	19	369
Revisions of Previous Estimates [3]	(57)	9	—	(48)
Extensions, Discoveries and Other Additions [4]	106	—	1	107
Purchase of Minerals in Place [5]	—	—	—	—
Sale of Minerals in Place [6]	(25)	—	(4)	(29)
Production [7]	(24)	(15)	(3)	(42)
December 31, 2012	244	100	13	357
Revisions of Previous Estimates [3]	20	7	—	27
Extensions, Discoveries and Other Additions [4]	113	1	1	115
Purchase of Minerals in Place [5]	3	—	—	3
Sale of Minerals in Place [6]	(20)	—	(2)	(22)
Production [7]	(29)	(14)	(2)	(45)
December 31, 2013	331	94	10	435
Proved Developed Reserves as of				
December 31, 2010	119	43	21	183
December 31, 2011	134	60	13	207
December 31, 2012	130	60	8	198
December 31, 2013	147	75	8	230
Proved Undeveloped Reserves as of				
December 31, 2010	106	69	7	182
December 31, 2011	110	46	6	162
December 31, 2012	114	40	5	159
December 31, 2013	185	19	2	206

(1) United States NGL proved reserves totaled:

	United States NGL Reserves (MMBbls)		
	Proved Developed	Proved Undeveloped	Total Proved
December 31, 2010	38	23	61
December 31, 2011	49	24	73
December 31, 2012	42	30	72
December 31, 2013	44	51	95

(2) Other International includes China, the North Sea and Israel.

(3) The 2011 US revisions were primarily associated with reclassification of vertical PUDs to probable reserves in the DJ Basin which were no longer expected to be developed in five years due to shifting emphasis from vertical to horizontal development, partially offset by positive revisions in other onshore US fields. International revisions were associated with performance revisions in China and the North Sea.

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 are 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.

(4) The 2011 increase was from development of onshore assets, primarily in the DJ Basin.

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.

(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.

(7) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2013, 2012 and 2011.

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

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

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

	Natural Gas and Casinghead Gas (Bcf)				
	United States	Equatorial Guinea	Israel	Other Int'l (1)	Total
Proved Reserves as of:					
December 31, 2010	1,626	869	1,844	22	4,361
Revisions of Previous Estimates (2)	(241)	7	—	(8)	(242)
Extensions, Discoveries and Other Additions (3)	326	—	488	—	814
Purchase of Minerals in Place (4)	406	—	—	—	406
Sale of Minerals in Place (5)	—	—	—	—	—
Production	(141)	(90)	(63)	(2)	(296)
December 31, 2011	1,976	786	2,269	12	5,043
Revisions of Previous Estimates (2)	(266)	2	(24)	—	(288)
Extensions, Discoveries and Other Additions (3)	601	16	42	—	659
Purchase of Minerals in Place (4)	—	—	—	—	—
Sale of Minerals in Place (5)	(164)	—	—	(2)	(166)
Production	(160)	(86)	(37)	(1)	(284)
December 31, 2012	1,987	718	2,250	9	4,964
Revisions of Previous Estimates (2)	262	24	124	—	410
Extensions, Discoveries and Other Additions (3)	587	41	181	—	809
Purchase of Minerals in Place (4)	126	—	—	—	126
Sale of Minerals in Place (5)	(145)	—	—	(6)	(151)
Production	(161)	(92)	(76)	(1)	(330)
December 31, 2013	2,656	691	2,479	2	5,828
Proved Developed Reserves as of					
December 31, 2010	1,156	597	145	19	1,917
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
Proved Undeveloped Reserves as of					
December 31, 2010	470	272	1,699	3	2,444
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

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

(2) The 2011 US revisions were primarily associated with reclassification of vertical PUDs in the DJ Basin which were no longer expected to be developed in five years due to shifting activity level from vertical to horizontal development and revisions to onshore dry gas assets due to reduced activity assumptions, performance, and price. International revisions were associated with performance revisions in the North Sea.

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 are 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.

(3) The 2011 increase in the US was primarily due to active development programs in the DJ Basin and the Marcellus Shale. The increase in Israel was primarily due to continuing appraisal at Tamar and included reserves for Noa which we decided to develop.

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.

The 2013 increase in US reserves include 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.

(4) The increase related to the Marcellus Shale asset acquisition in 2011.

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

(5) 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.

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

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Results of Operations for Oil and Gas Producing Activities (Unaudited) Aggregate results of operations for crude oil and natural gas producing activities are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
(millions)					
Year Ended December 31, 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
Year Ended December 31, 2011					
Revenues	$ 2,124	$ 592	$ 307	$ 513	$ 3,536
Production Costs [2]	453	71	26	123	673
Exploration Expense	116	67	6	90	279
DD&A	732	70	25	113	940
Asset Impairments	757	—	—	2	759
Income before Income Taxes	66	384	250	185	885
Income Tax Expense	24	96	72	74	266
Results of Operations [4]	$ 42	$ 288	$ 178	$ 111	$ 619

(1) Other International includes the North Sea, China, Cameroon, Cyprus, Senegal/Guinea-Bissau (through 2011), Nicaragua, Falkland Islands, Sierra Leone 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 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 8. Derivative Instruments and Hedging Activities.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) [(1)]

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

(millions)	United States	Equatorial Guinea	Israel	Other Int'l [(2)]	Total
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 LLC 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 LLC development costs	$ 55	—	—	—	$ 55
Year Ended December 31, 2011					
Property Acquisition Costs					
Proved [(6)]	$ 392	$ —	$ —	$ —	$ 392
Unproved [(3)]	942	—	—	40	982
Total Acquisition Costs	1,334	—	—	40	1,374
Exploration Costs [(4)]	241	54	146	152	593
Development Costs [(5)]	1,511	499	485	37	2,532
Total Consolidated Operations	$ 3,086	$ 553	$ 631	$ 229	$ 4,499
Company's share of CONE LLC development costs	$ 60	—	—	—	$ 60

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes Cameroon, China, Cyprus, Falkland Islands, the North Sea, Nicaragua, Sierra Leone, and Senegal/Guinea-Bissau (through December 31, 2011). See Note 3. Property Transactions.

(3) 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.

2011 unproved property acquisition costs include: $853 million related to the Marcellus Shale asset acquisition, $40 million related to our position offshore Senegal/Guinea-Bissau, $31 million related to additional acreage in the DJ Basin and $58 million related to other onshore US.

(4) 2013 exploration costs include drilling and completion of $106 million in the deepwater Gulf of Mexico, $23 million in northeast Nevada, $19 million in the Marcellus Shale, $11 million in the DJ Basin, $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.

2011 exploration costs include drilling and completion costs of $74 million in deepwater Gulf of Mexico, $146 million in Israel, $54 million in Equatorial Guinea, $59 million in Cyprus, $36 million in Senegal/Guinea-Bissau and $42 million in the DJ Basin.

(5) Worldwide development costs include amounts spent to develop PUDs of approximately $1.0 billion in 2013, $1.8 billion in 2012 and $1.4 billion in 2011.

US development costs include increases in asset retirement obligations of $214 million in 2013, $73 million in 2012, and $115 million in 2011. Other international development costs include increases in asset retirement obligations of $32 million in 2013, $72 million in 2012, and $13 million in 2011.

Equatorial Guinea development costs include non-cash accruals related to estimated construction progress to date on an FSPO used in the development of the Aseng field of $66 million in 2011. These capitalized costs were included in development costs as the Aseng FPSO was constructed.

(6) Proved property acquisition costs include $386 million related to the Marcellus Shale asset acquisition in 2011.

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,	
	2013	2012
(millions)		
Unproved Oil and Gas Properties [1]	$ 1,463	$ 1,399
Proved Oil and Gas Properties [2]	21,195	18,297
Total Oil and Gas Properties	22,658	19,696
Accumulated DD&A [3]	(7,082)	(6,252)
Net Capitalized Costs	$ 15,576	$ 13,444
Company's share of CONE LLC Net Capitalized Costs	$ 179	$ 118

(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 $860 million and $740 million at December 31, 2013 and 2012, respectively.

(2) 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.

Proved oil and gas properties at December 31, 2012 include North Sea assets held for sale of $200 million and asset retirement costs of $334 million.

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

Accumulated DD&A at December 31, 2012 includes $160 million related to North Sea assets held for sale. See Note 3. Property Transactions.

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	Other Int'l [1]	Total
(millions)					
December 31, 2013					
Future Cash Inflows [2]	$ 34,611	$ 9,393	$ 15,046	$ 726	$ 59,776
Future Production Costs [3]	8,901	2,364	1,742	293	13,300
Future Development Costs	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 [2]	$ 23,495	$ 10,318	$ 14,608	$ 1,171	$ 49,592
Future Production Costs [3]	6,531	2,148	942	487	10,108
Future Development Costs	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
December 31, 2011					
Future Cash Inflows [2]	$ 27,663	$ 11,112	$ 13,603	$ 1,806	$ 54,184
Future Production Costs [3]	7,367	1,808	1,144	496	10,815
Future Development Costs	5,283	716	639	267	6,905
Future Income Tax Expense	4,939	2,028	2,407	471	9,845
Future Net Cash Flows	10,074	6,560	9,413	572	26,619
10% Annual Discount for Estimated Timing of Cash Flows	4,930	2,110	6,203	87	13,330
Standardized Measure of Discounted Future Net Cash Flows	$ 5,144	$ 4,450	$ 3,210	$ 485	$ 13,289

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

(2) The standardized measure of discounted future net cash flows does not include cash flows relating to anticipated future methanol sales.

(3) Production costs include oil and gas lease operating expense, production and ad valorem taxes, transportation expense and general and administrative expense supporting oil and gas operations.

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, 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	—	—	—	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	—	—	—	40.11
December 31, 2011					
Average Crude Oil and Condensate Price per Bbl	$ 91.44	$ 103.01	$ 99.92	$ 111.50	$ 96.73
Average Natural Gas Price per Mcf	4.24	0.25	5.85	6.55	4.35
Average NGL Price per Bbl	49.36	—	—	—	49.36

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

We estimate that a $1.00 per Bbl change in the average price of crude oil from the 12-month average price for 2013 would change the discounted future net cash flows before income taxes by approximately $253 million. We estimate that a $0.10 per Mcf change in the average price of natural gas from the 12-month average price for 2013 would change the discounted future net cash flows before income taxes by approximately $262 million.

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 and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future development costs include amounts that we expect to spend to develop PUDs of $3.2 billion in 2014, $2.1 billion in 2015 and $1.2 billion in 2016.

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 and natural gas reserves, less the tax bases of the properties involved. Future income tax expense gives effect to tax credits and allowances, but does not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

Imbalance receivables and liabilities are as follows:

	Year Ended December 31, 2013	2012	2011
(millions)			
Imbalance Receivables	$ 31	$ 29	$ 28
Imbalance Liabilities	29	25	22

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

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 and natural gas reserves are as follows:

	Year Ended December 31,		
	2013	2012	2011
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$13,081	$13,289	$ 9,006
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(3,937)	(3,463)	(2,864)
Net Changes in Prices and Production Costs	(237)	(1,902)	4,926
Extensions, Discoveries and Improved Recovery, Less Related Costs	3,386	1,811	2,039
Changes in Estimated Future Development Costs	(1,825)	1,042	(710)
Development Costs Incurred During the Period	3,195	2,988	2,529
Revisions of Previous Quantity Estimates	1,541	(1,256)	(1,320)
Purchases of Minerals in Place	78	—	115
Sales of Minerals in Place	(768)	(1,141)	(6)
Accretion of Discount	1,765	1,860	1,278
Net Change in Income Taxes	(780)	732	(1,540)
Change in Timing of Estimated Future Production and Other	(1,409)	(879)	(164)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	1,009	(208)	4,283
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$14,090	$13,081	$13,289

Noble Energy, Inc.
Supplemental Quarterly Financial Information
(Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended				
	March 31,	June 30,	Sep 30,	Dec 31,	Total
(millions except per share amounts)					
2013 [1]					
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
2012 [2]					
Revenues	$ 1,088	$ 965	$ 1,003	$ 1,167	$ 4,223
Income from Continuing Operations Before Income Taxes	335	390	275	356	1,356
Income from Continuing Operations	249	275	164	277	965
Discontinued Operations, Net of Tax	14	17	57	(26)	62
Net Income	263	292	221	251	1,027
Basic Earnings (Loss) Per Share [3]					
Income from Continuing Operations	$ 0.70	$ 0.77	$ 0.46	$ 0.78	$ 2.71
Discontinued Operations, Net of Tax	0.04	0.05	0.16	(0.07)	0.18
Net Income	0.74	0.82	0.62	0.71	2.89
Diluted Earnings (Loss) Per Share [3] [4]					
Income from Continuing Operations	$ 0.70	$ 0.75	$ 0.46	$ 0.77	$ 2.68
Discontinued Operations, Net of Tax	0.04	0.04	0.16	(0.07)	0.18
Net Income	0.74	0.79	0.62	0.70	2.86

(1) First quarter 2013 included the following:
- $72 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $79 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $12 million pre-tax gain on sale of non-core asset (See Note 3. Property Transactions).

Second quarter 2013 included the following:
- $161 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $159 million (See Note 8. Derivative Instruments and Hedging Activities).

Third quarter 2013 included the following:
- $157 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $147 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $63 million impairment charges (See Note 4. Asset Impairments).

Fourth quarter 2013 included the following:
- $23 million impairment charges (See Note 4. Asset Impairments);
- $24 million pre-tax gain on sale of non-core onshore US assets (See Note 3. Property Transactions); and

- $65 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $64 million (See Note 8. Derivative Instruments and Hedging Activities).

(2) First quarter 2012 included the following:

- $96 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $73 million (See Note 8. Derivative Instruments and Hedging Activities).

Second quarter 2012 included the following:

- $73 million asset impairment charges (See Note 4. Asset Impairments);
- $276 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $277 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $9 million pre-tax gain on sale of non-core onshore US assets (See Note 3. Property Transactions).

Third quarter 2012 included the following:

- $135 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $131 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $157 million pre-tax gain on sale of non-core onshore US assets (See Note 3. Property Transactions).

Fourth quarter 2012 included the following:

- $31 million impairment charges (See Note 4. Asset Impairments);
- $13 million pre-tax loss on sale of non-core onshore US assets (See Note 3. Property Transactions); and
- $30 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $36 million (See Note 8. Derivative Instruments and Hedging Activities).

(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 the three months ended June 30, 2012 excludes deferred compensation gains of $7 million, net of tax.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in the reports that we file or furnish under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management's Annual Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Management's Report on Internal Control over Financial Reporting, included in Item 8. Financial Statements and Supplementary Data.

The independent auditor's attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting), included in Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control over Financial Reporting

Our management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with US GAAP.

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

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2013. 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.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

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 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

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

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

PART IV

Item 15. Exhibits and Financial Statement Schedules

a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

SIGNATURES

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

	NOBLE ENERGY, INC. (Registrant)
Date: February 6, 2014	By: /s/ Charles D. Davidson
	Charles D. Davidson, Chairman of the Board, Chief Executive Officer and Director
Date: February 6, 2014	By: /s/ Kenneth M. Fisher
	Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date: February 6, 2014	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/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	February 6, 2014
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 6, 2014
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 6, 2014
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 6, 2014
/s/ Michael A. Cawley Michael A. Cawley	Director	February 6, 2014
/s/ Edward F. Cox Edward F. Cox	Director	February 6, 2014
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 6, 2014
/s/ Eric P. Grubman Eric P. Grubman	Director	February 6, 2014
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 6, 2014
/s/ Scott D. Urban Scott D. Urban	Director	February 6, 2014
/s/ William T. Van Kleef William T. Van Kleef	Director	February 6, 2014
/s/ Molly K. Williamson Molly K. Williamson	Director	February 6, 2014

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 the Registrant's 8¼% Notes Due March 1, 2019 (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 8¼% Notes Due March 1, 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 senior debt securities of Noble Energy, Inc. (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 senior debt securities of Noble Energy, Inc. (including the form of 2021 Notes) (filed as Exhibit 4.1 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 senior debt securities of Noble Energy, Inc. (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	—	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 form of the Registrant's 7¼% Notes Due 2023 (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).
4.9	—	Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.10	—	First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (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	—	Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7¼% Senior Debentures Due 2097 dated as of August 1, 1997 (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).
4.12	—	Third Indenture Supplement relating to $200 million of the Registrant's 5¼% Notes due 2014 dated April 19, 2004 between the Company and the Bank of New York Trust Company, N.A., as successor trustee to U.S. Trust Company of Texas, N.A. (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-116092) and incorporated herein by reference).

Exhibit Number		Exhibit **
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*	—	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.6*	—	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).
10.7*	—	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).
10.8	—	$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).
10.9	—	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).
10.10*	—	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).
10.11*	—	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).
10.12*	—	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).
10.13*	—	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).
10.14*	—	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).
10.15*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 27, 2009) filed on February 2, 2009 and incorporated herein by reference).
10.16*	—	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).
10.17*	—	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).

Exhibit Number		Exhibit **
10.18*	—	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).
10.19*	—	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).
10.20*	—	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).
10.21*	—	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 Company'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 Company'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 Rodney D. Cook, Senior Vice President, dated May 1, 2013 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013 and incorporated herein by reference).
10.30*	—	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).
10.31*	—	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).
10.32*	—	Form of Restricted Stock Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.25 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 and incorporated herein by reference).
10.33*	—	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).
10.34*	—	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).

Exhibit Number		Exhibit **
10.35*	—	Amendment to Retention and Confidentiality Agreement between Noble Energy, Inc. and Rodney D. Cook, Senior Vice President, dated January 28, 2014, filed herewith.
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 Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), 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.

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
PSC	Production sharing contract
Tcf	Trillion cubic feet
US GAAP	United States generally accepted accounting principles
WTI	West Texas Intermediate index