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, 2012
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)
100 Glenborough Drive, Suite 100	
Houston, Texas	**77067**
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

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

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

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

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

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2012: $15.1 billion.

Number of shares of Common Stock outstanding as of January 18, 2013: 178,714,869.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2013 Annual Meeting of Stockholders to be held on April 23, 2013, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2012, are incorporated by reference into Part III.

TABLE OF CONTENTS

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 meter
BOE	Barrels oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of 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 oil equivalent for natural gas is significantly less than the price for a barrel of 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

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 – Disclosure Regarding Forward-Looking Statements of this Form 10-K.

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 by Lloyd Noble in 1932, we recently celebrated the 80th anniversary of our founding. 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 deliver energy through crude oil and natural gas exploration and production while embracing our responsibility to be a good corporate citizen and 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, lead our industry, respect our environment and care for our people and the communities where we operate. In 2012, we published our first Sustainability Report.

We aim to achieve sustainable growth in value and cash flow through exploration success and the development of a high-quality, diversified and growing portfolio of assets that is balanced between US and international projects. Exploration success, along with additional 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 diversified, growing asset portfolio offering superior returns to investors.

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 highly capable major development project execution. Our first major offshore development project, Aseng, offshore Equatorial Guinea, began production in late 2011. We followed our success at Aseng with our second major development project, Galapagos, in the deepwater Gulf of Mexico, which began commercial crude oil production in June 2012. We remain on schedule with two major development projects, Tamar, offshore Israel, and Alen, offshore Equatorial Guinea, scheduled to begin commercial production in the second and third quarters of 2013, respectively. Our ability to deliver these major development projects on schedule and budget provides a competitive and financial advantage in the industry.

Onshore US assets provide a stable base of production along with growing development programs and accommodate flexible capital spending programs 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-term offshore development projects, while requiring multi-year capital investment, are expected to offer superior financial returns and cash flow coupled with sustained production. Our portfolio offers a diverse production mix among crude oil, US natural gas, and international natural gas.

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 and natural gas 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 cash dividends have increased 38% in the last five years, from 66 cents per share in 2008 to 91 cents per share in 2012. 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 2008-2012.

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 are moving forward on 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 and development drilling, front-end engineering and design, construction and exploitation. We currently have projects in all phases of the development cycle with some contributing production growth in 2012 and 2013, and others we are working to sanction with final investment decisions targeting first production from 2015 and beyond. Although these projects will require significant capital investments over the next several years, they typically offer long-life, sustained cash flows after investment and attractive financial returns. Our major development projects resulting from exploration success and strategic acquisitions include the following:

Sanctioned Projects

- Horizontal Niobrara (onshore US)
- Marcellus Shale (onshore US)
- Tamar (offshore Israel)
- Alen (offshore Equatorial Guinea)

Unsanctioned Projects

- Gunflint (deepwater Gulf of Mexico)
- Big Bend (deepwater Gulf of Mexico)
- Leviathan (offshore Israel)
- Cyprus (offshore Cyprus)
- Carla and Diega (offshore Equatorial Guinea)
- West Africa gas project (offshore Equatorial Guinea)

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, 2012 were as follows:

Summary of 2012 Oil and Gas Reserves as of Fiscal-Year End
Based on Average 2012 Fiscal-Year Prices

	December 31, 2012		
	Proved Reserves		
	Crude Oil, Condensate & NGLs	Natural Gas	Total
Reserves Category	(MMBbls)	(Bcf)	(MMBoe)
Proved Developed			
United States	130	1,042	303
Equatorial Guinea	60	514	146
Israel	—	18	3
Other International [(1)]	8	8	9
Total Proved Developed Reserves	198	1,582	461
Proved Undeveloped			
United States	114	945	272
Equatorial Guinea	40	204	74
Israel	3	2,232	375
Other International [(1)]	2	1	2
Total Proved Undeveloped Reserves	159	3,382	723
Total Proved Reserves	357	4,964	1,184

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

Total proved reserves as of December 31, 2012 were approximately 1.2 BBoe, a 2% decrease from 2011. US proved reserves accounted for 49% of the total, and international proved reserves accounted for 51%. Our 2012 proved reserves mix is 30% global liquids, 42% international natural gas, and 28% 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 areas of interest. These activities include geophysical and geological evaluation 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 which 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, such as proprietary seismic data and operational expertise, and which we believe generate superior returns. We have had substantial exploration success onshore US and 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 industry-leading exploration program. During 2012, we expanded our global presence by entering into three new areas, onshore Northeast Nevada, offshore Falkland Islands and offshore Sierra Leone.

Appraisal, Development and Exploitation Activities Our exploration success and strategic acquisitions have provided us with numerous appraisal, development, and exploitation opportunities, as demonstrated in our growing inventory of major development projects. In 2012, we commenced crude oil production from Galapagos, deepwater Gulf of Mexico, our second major offshore development project, brought online following the start up of Aseng in 2011. Additionally, we continued to make significant progress on our 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 in order to optimize our asset portfolio.

Strategic Partner for Leviathan The Leviathan field, offshore Israel, is the largest conventional natural gas discovery in our history, with resources sufficient for both domestic demand and export. During 2012, we and our existing partners in the Leviathan project commenced a process to identify a partner who could provide technical and financial support as well as midstream and downstream expertise. On December 2, 2012, we and our existing partners announced that we had agreed in principle on a proposal to sell a 30% working interest in the Leviathan licenses to Woodside Energy Ltd. (Woodside). Woodside is Australia's largest producer of LNG with over 25 years of experience and has strong working relationships with many potential customers in the Asian LNG markets. We expect to execute a final agreement with Woodside during the first half of 2013. See Eastern Mediterranean (Israel and Cyprus) - *Woodside Agreement*, below.

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-growth, superior return areas. Proceeds from divestitures provide additional flexibility in the implementation of our international exploration and development programs and the acceleration of horizontal drilling activities in the DJ Basin and Marcellus Shale. During 2012, divestitures generated net proceeds of approximately $1.2 billion.

On August 13, 2012, we sold our 30% non-operated working interests in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea, for $117 million, after final closing adjustments from the January 1, 2012 effective date. Net daily production from these properties was approximately 5 MBoe/d at the time of the sale.

During the third quarter of 2012, we closed on three sales of onshore US properties in Kansas, western Oklahoma, western Texas, and the Texas Panhandle for total proceeds of $1.0 billion. The properties included our interests in about 1,400 producing wells on approximately 109,000 net acres. As of the effective date, April 1, 2012, net daily production on these properties was approximately 12.5 MBoe/d.

We sold approximately 57 MMBoe of proved reserves in 2012 and continue to market packages of non-core onshore US properties and our remaining North Sea properties.

Entry into Falkland Islands Joint Venture In August 2012, we entered into an agreement with Falkland Oil and Gas Limited (FOGL) and subsequently acquired an interest in FOGL's extensive license areas consisting of approximately 10 million undeveloped acres, gross, located south and east of the Falkland Islands.

Entry into Sierra Leone In September 2012, the Government of Sierra Leone awarded us participation in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million acres, gross. Under the terms of the award, Chevron (SL) Ltd. will be the operator and we will have a non-operated 30% working interest.

Exit from Senegal/Guinea-Bissau In 2012, we decided not to continue to participate in further appraisal activities and relinquished our acreage.

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, 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.

Entry into Marcellus Shale Joint Venture On September 30, 2011, we entered into an agreement with a subsidiary of CONSOL Energy Inc. (CONSOL) to jointly develop oil and gas assets in the Marcellus Shale areas of southwest Pennsylvania and northwest West Virginia. The Marcellus Shale joint venture strengthens and diversifies our portfolio, providing a new, material growth area, which we believe will contribute to future reserves, production, and cash flows. This transaction complements and further strengthens our US portfolio by adding a high-quality asset, with substantial growth potential that is close to the US's largest gas market, the Northeast US. It significantly increases our inventory of low risk, repeatable development projects while exposing us to more US unconventional resources. The Marcellus Shale joint venture, combined with our other domestic projects in the DJ Basin and the deepwater Gulf of Mexico, provides diversity to our rapidly expanding international programs.

DJ Basin Asset Acquisition In March 2010, we acquired substantially all of the US Rocky Mountain oil and gas assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for a total purchase price of $498 million. The acquisition included properties located in the DJ Basin, one of our core operating areas.

Onshore US Sale In August 2010, we closed the sale of non-core assets in the Mid-Continent and Illinois Basin areas for cash proceeds of $552 million and recorded a gain of $110 million.

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 2012, we recorded impairment charges of $104 million, related to our South Raton and Piceance developments due to near-term declines in crude oil and natural gas prices, respectively, and our Mari-B, Pinnacles and Noa fields, offshore Israel, due to end-of-field life declines in production. 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, exploitation and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 60% of 2012 total consolidated sales volumes and 49% of total proved reserves at December 31, 2012. Approximately 58% of the proved reserves are natural gas and 42% are crude oil, condensate and NGLs.

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

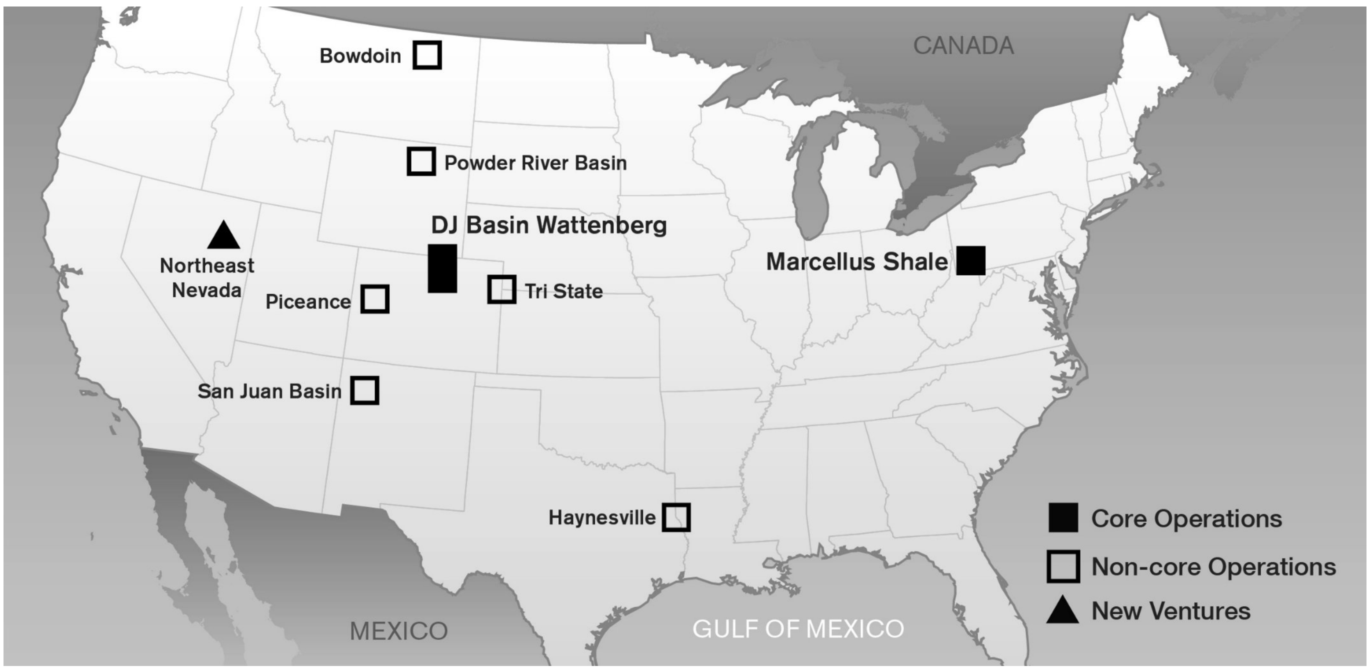
	Year Ended December 31, 2012				December 31, 2012			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
Wattenberg	32	194	13	77	150	880	61	358
Marcellus Shale	—	90	—	15	—	827	8	146
Rockies	2	117	2	24	—	203	3	37
Deepwater Gulf of Mexico	14	14	1	18	19	21	—	23
Gulf Coast and Other	1	23	—	5	3	56	—	11
Total	49	438	16	139	172	1,987	72	575

Wells drilled in 2012 and productive wells at December 31, 2012 for our US operating areas were as follows:

	Year Ended December 31, 2012	December 31, 2012
	Gross Wells Drilled or Participated in (1)	Gross Productive Wells
Wattenberg	555	8,954
Marcellus Shale	71	173
Rockies	24	4,210
Deepwater Gulf of Mexico	1	11
Gulf Coast and Other	—	313
Total	651	13,661

(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, 2012 are shown on the map below:



DJ Basin / Wattenberg The DJ Basin, where we have an acreage position of approximately 750,000 net acres, is a premier US crude oil resource play and is significant to our production growth and development activities. Included in the DJ Basin is Wattenberg (approximately 95% operated working interest), our largest onshore US asset, where we have a multi-year project inventory. In 2012, we continued to improve our operational performance while accelerating our drilling activities. During 2012, we had record sales volumes in the DJ Basin due to continued strong performance from our horizontal drilling program that began in 2010.

Wattenberg includes:

- the Greater Wattenberg Area (GWA), where we have conducted substantial vertical development over the last several years as well as successful horizontal drilling in the high density area and more recently in the less developed northeastern part of GWA. The area is comprised of both an expanding crude oil window to the northeast and strong natural gas window in the core and to the southwest; and
- northern Colorado from the edge of the GWA to the Wyoming border where we expanded our acreage position and drilled over 25 wells during 2012.

During 2012, we spud a total of 410 development wells in Wattenberg, of which 195 were horizontal wells into the Niobrara and Codell formations. In 2011, we began constructing multi-well horizontal drilling pads and centralized production facilities to minimize our surface use (EcoNode). The EcoNode allows for more efficient execution and operations by reducing our land use and surface traffic, water usage and moving the program forward with less surface impact. We continue to evaluate impacts of changes in well spacing and pad design. Included in the well numbers above, we spud 10 extended-reach (7,000 - 9,000 feet) lateral wells as part of the 2012 drilling program and are planning for approximately 20% of our 2013 drilling program to be extended-reach wells.

Wattenberg contributed an average of 77 MBoe/d of sales volumes, represented approximately 33% of total consolidated sales volumes in 2012, with approximately 58% being liquids, and approximately 358 MMBoe or 31% of total proved reserves at December 31, 2012. Horizontal drilling in the Niobrara formation has significantly expanded the economic limits of this field. Of the net sales volumes from Wattenberg, approximately 28 MBoe/d, came from a total of 279 producing wells in our horizontal Niobrara program.

During 2012, we continued to expand our horizontal Niobrara development activities into Northern Colorado, where recent results indicate recoveries comparable to those in the GWA. We added almost 26,000 net acres to our Northern Colorado position this year, increasing our acreage position to approximately 230,000 net acres. We expect to spud approximately 80 to 90 wells in this area during 2013, further accelerating our horizontal Niobrara development.

Our 2012 Wattenberg development program resulted in additions to proved reserves of approximately 55 MMBoe, approximately 72% of which are liquids.

Our DJ Basin position gives us opportunities to expand beyond our GWA development activities. We have also expanded into Wyoming and continue to appraise this acreage.

Marcellus Shale A joint venture partnership with CONSOL Energy Inc. (CONSOL), formed in September 2011, the Marcellus Shale represents our second onshore US core area. We hold a 50% interest in approximately 628,000 net acres in southwest Pennsylvania and northwest West Virginia. We operate the wet gas development area while CONSOL operates the dry gas development area.

During 2012, we drilled to total depths approximately 25 wet gas wells and began wet gas production in July 2012. By applying our DJ Basin experience, we continue to test the limits of our recovery techniques with longer lateral wells, improved hydraulic fracturing design and optimal well placements. As we move into new areas, water supply and gas gathering infrastructure are expanding. Our partner, CONSOL, drilled to total depths 64 dry gas wells during 2012. Although we have reduced drilling in the dry gas area due to the low natural gas price environment, the dry gas portion of the program continues to deliver economically attractive returns due to strong production performance, high net revenue interests, competitive costs, partner alignment, and access to the US's largest gas market in the Northeast.

The Marcellus Shale contributed an average of 15 MBoe/d of sales volumes and represented approximately 6% of total consolidated sales volumes in 2012, with approximately 1% being liquids, and approximately 146 MMBoe or 12% of total proved reserves at December 31, 2012.

Our joint development plan for 2013 projects that we will drill to total depth approximately 90 horizontal wells in the wet gas areas and CONSOL will drill to total depth approximately 36 horizontal wells focused in the dry gas areas of the Marcellus Shale.

The large portion of acreage that is currently held by production should allow for efficient development utilizing pad drilling. Pad drilling minimizes our surface use as well as the permitting and infrastructure requirements.

Hydraulic Fracturing We find that the use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs, including the DJ Basin and the Marcellus Shale. Hydraulic fracturing involves the injection of a mixture of pressurized water, sand and a small amount of chemicals into rock formations in order to stimulate production of natural gas and/or oil from dense subsurface rock formations, including shale. The majority of our onshore US proved undeveloped reserves, which totaled 265 MMBoe at December 31, 2012, will require the use of hydraulic fracturing to produce commercial quantities of crude oil and natural gas. See Hydraulic Fracturing, below, for more discussion.

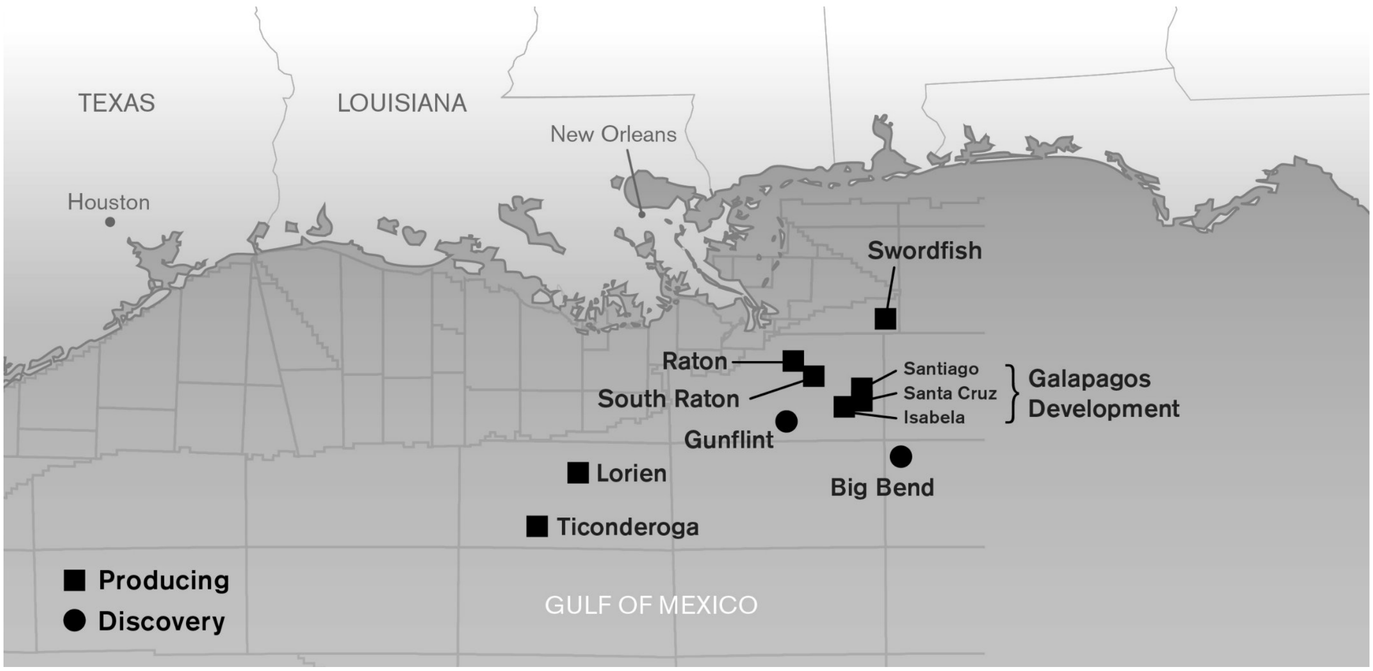
Natural Gas Flaring The practice of natural gas flaring (burning) is the safest way to dispose of natural gas associated with crude oil production when no gas infrastructure is available. The volume of natural gas being flared is growing in certain areas of the US, such as the Bakken Shale, primarily as a result of increased oil shale drilling activity and limited natural gas infrastructure. In these areas, public concern has grown about the potential impact of GHG emissions from flaring on the environment, as well as the potential waste of natural resources.

In our DJ Basin and Marcellus Shale operations, natural gas infrastructure build out generally occurs in advance of drilling activity. If short-term flaring is necessary, we use efficient, environmentally protective and energy-saving flaring technologies. We participate in the Carbon Disclosure Project by publicly disclosing, on a voluntary basis, information pertaining to our GHG emissions.

Northeast Nevada We constantly strive to identify new onshore exploration opportunities with reasonable entry cost, significant running room and the potential to become a new core area. We have a 350,000 net acre position (66% fee acreage and remainder federal acreage) in Northeast Nevada, prospective for oil exploration, which we identified through basin scale reconnaissance and innovative geoscience concepts. We acquired 3-D seismic over portions of the acreage in 2012 with a vertical well exploratory drilling program scheduled to begin in 2013.

Other 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), San Juan Basin (Northwestern New Mexico), and Powder River Basin (North/Central Wyoming); and Gulf Coast including the Haynesville field (East Texas and North Louisiana) and other properties in Texas and Louisiana. Other onshore properties accounted for 13% of total consolidated sales volumes in 2012 and 4% of total proved reserves at December 31, 2012. Although our future development focus is concentrated on our core areas, we continue to produce and develop in these other areas. We drilled 22 development wells during 2012. During 2012, we completed the sale of 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 deepwater Gulf of Mexico developments as of December 31, 2012 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 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 8% of total consolidated sales volumes in 2012 and 2% of total proved reserves at December 31, 2012. We currently hold leases on 102 deepwater Gulf of Mexico blocks, representing approximately 596,000 gross acres (414,000 net acres). Of our total gross acres, approximately 96,000 gross acres (41,000 net acres) have been developed. We are the operator on approximately 86% of our leases. See also Developed and Undeveloped Acreage - *Future Acreage Expirations*, below.

Deepwater Gulf of Mexico Exploration Program Our deepwater Gulf of Mexico operations resulted from lease acquisition, expansion of our 3-D seismic database, and an active drilling program. We currently have an inventory of 31 identified prospects, which are a combination of both high impact stand-alone subsalt prospects and smaller, high value tie-back opportunities. The prospects are subject to an ongoing rigorous 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 most of 2013 with four additional one year option elections. We also have the ENSCO 8505 rig under contract through 2014 in a rig share agreement with two other operators; however, we farmed out our 2013 drilling slot to our rig partners. In 2013, we plan to drill a Gunflint appraisal well and at least one exploration well.

Big Bend During 2012, we drilled the successful Big Bend exploration well. The well is located in Mississippi Canyon Block 698 and was drilled to a total depth of 15,989 feet. We hold a 54% operated working interest in Big Bend. Logging results identified approximately 150 feet of net oil pay in two high-quality reservoirs. We anticipate sanctioning a development plan for Big Bend during 2013 with first production targeted in late 2015 or early 2016.

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

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. During 2012, we completed the subsea tieback to the nearby Nakika production platform and began production in June. The Galapagos development has significantly increased our offshore production in 2012 with flow rates up to approximately 13.5 MBoe/d, net.

Gunflint (Mississippi Canyon Block 948; 26% operated working interest) Gunflint is a 2008 crude oil discovery, our largest deepwater Gulf of Mexico discovery to date. In July 2012, we drilled a successful Gunflint appraisal well. During first quarter of 2013, we plan to drill our second appraisal well targeting the southern area of the reservoir. Front-end conceptual studies have been completed, and we are working toward sanctioning of a scalable development project in 2013. We are currently targeting 2017 for production start-up utilizing a standalone facility. If we choose to connect to an existing third-party host, the project could have an accelerated completion schedule.

Raton/South Raton (Mississippi Canyon Blocks 248 and 292) Raton (67% operated working interest) was a 2006 natural gas discovery and has been producing since 2008. South Raton (79% operated working interest) was a 2008 crude oil discovery. During the second quarter of 2012, the South Raton crude oil development project commenced production at approximately 3 MBbl/d, net. South Raton is tied back to a non-operated host facility. We are currently evaluating mechanical issues at South Raton, which is temporarily offline.

Swordfish (Viosca Knoll Blocks 917, 961 and 962; 85% operated working interest) Swordfish was a 2001 crude oil discovery and began producing in 2005. The Swordfish project currently includes two producing wells connected to a third-party production facility through subsea tiebacks.

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

Lorien (Green Canyon Block 199; 60% operated working interest) Lorien was a 2003 crude oil discovery and began producing in 2006. The project currently includes one producing well connected to existing infrastructure through subea tiebacks.

International

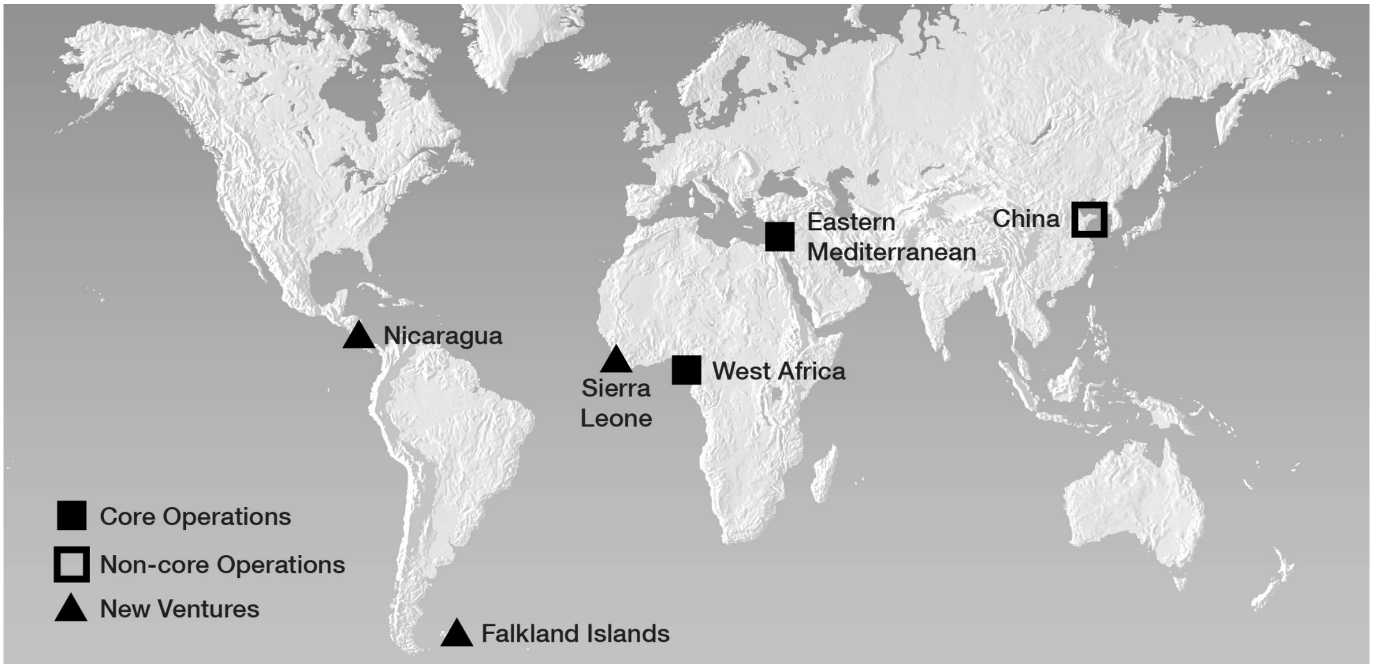
Our international business focuses on offshore opportunities in multiple countries and provides diversity to our portfolio. Development projects in Equatorial Guinea, Israel, the North Sea, and China have contributed substantially to our growth over the last decade.

Significant recent 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 have large acreage positions in West Africa, the Eastern Mediterranean, and in 2012 we entered two new areas: offshore the Falkland Islands and offshore Sierra Leone. Each of these locations will provide further international exploration opportunities.

In furtherance of our commitment to global offshore exploration and development, on September 27, 2012, we announced that we have entered into a 36-month drilling services contract with a subsidiary of Atwood Oceanics, Inc. Drilling services will be provided by a new-build drillship, the Atwood *Advantage*. The Atwood *Advantage* is currently under construction by Daewoo Shipbuilding & Marine Engineering Co., Ltd. in South Korea. The drillship will be equipped with enhanced offline capabilities, such as dual blowout preventer stacks that allow for simultaneous inspection and drilling activities, and will be rated for operations in 12,000 feet water depth/40,000 feet drill depth. The increased mobility of the Atwood *Advantage*, as compared with other drilling rigs, will add flexibility to our global exploration program. We expect that the drillship will be available fourth quarter 2013 and initially deployed offshore Israel.

International operations accounted for 40% of total consolidated sales volumes in 2012 and 51% of total proved reserves at December 31, 2012. International proved reserves are approximately 81% natural gas and 19% crude oil and condensate. 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.

Locations of our international operations 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, 2012				December 31, 2012		
	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	33	235	—	72	100	718	220
Israel	—	101	—	17	3	2,250	378
China	4	—	—	4	7	2	7
Total International	37	336	—	93	110	2,970	605
Equity Investee	2	—	5	7	—	—	—
Discontinued Operations (North Sea)	5	4	—	5	3	7	4
Total	44	340	5	105	113	2,977	609
Equity Investee Share of Methanol Sales (MMgal)				156			

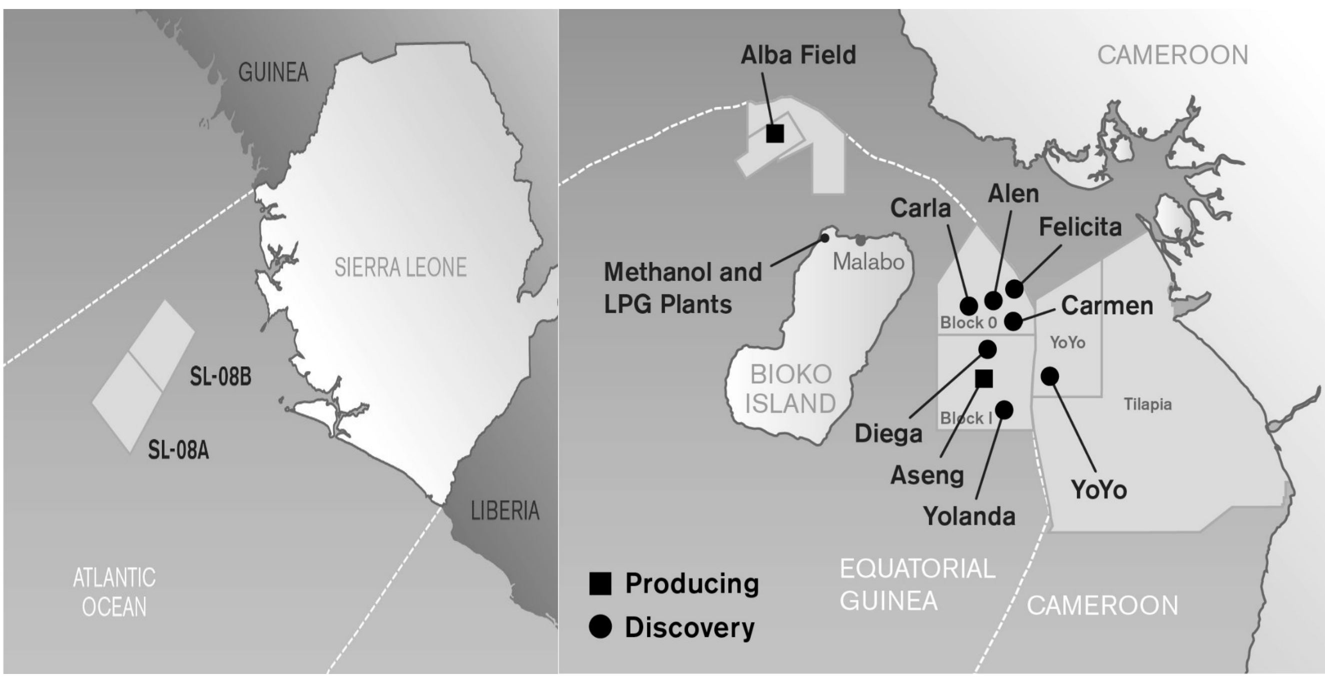
Wells drilled in 2012 and productive wells at December 31, 2012 in our international operating areas were as follows:

	Year Ended December 31, 2012	December 31, 2012
	Gross Wells Drilled or Participated in (1)	Gross Productive Wells
International		
Equatorial Guinea	4	23
Cameroon	1	—
Israel	8	9
North Sea	—	18
China	3	28
Total International	16	78

(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 new blocks offshore Sierra Leone. Equatorial Guinea, the only producing country in our West Africa segment, accounted for approximately 31% of 2012 total consolidated sales volumes and 18% of total proved reserves at December 31, 2012. At December 31, 2012, we held approximately 119,000 net developed acres and 80,000 net undeveloped acres in Equatorial Guinea, 542,000 net undeveloped acres in Cameroon, and 414,000 net undeveloped acres in Sierra Leone.

Locations of our operations in West Africa are shown on the map below:



Aseng Project Aseng is a crude oil development project on Block I (38% operated working interest) which includes five horizontal wells flowing to an FPSO (Aseng FPSO) where the production stream is separated. 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. We are the technical operator of the Aseng Project and have executed a crude oil sale, purchase, and marketing agreement with Glencore Energy UK Ltd. for our share of Aseng production.

The Aseng FPSO is designed to act as an oil production hub, as well as liquids storage and offloading hub, with capabilities to support future subsea oil field developments in the area. It also has the ability to process and store stabilized condensate from gas condensate fields in the area, the first of which will be Alen during the third quarter of 2013. It is capable of processing 120 MBbl/d of liquids, including 80 MBbl/d of oil, and reinjecting 160 MMcf/d of natural gas. The Aseng FPSO has storage capacity of approximately 1.6 MMBbls of liquids.

During 2012, Aseng maintained excellent reliability and safety performance and averaged almost 100% production uptime, while producing on average 62 MBbl/d, 21 MBbl/d net, to Noble Energy.

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 metric tons per day, gross. 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.

In December 2012, the Alba compression project was approved. We are beginning the engineering phase for a compression platform and related in-field connections in early 2013 with an estimated start-up in 2016.

Alen Project Alen, sanctioned in 2010, is located primarily on Block O (45% operated working interest), offshore Equatorial Guinea, and is our next West Africa major development project. Initial field development will include three production wells and three subsea natural gas injection wells tied to a processing facility. Produced condensate will be separated and piped to the Aseng FPSO utilizing the hub we are in the process of building in the region, where it will be held until sold. The associated natural gas will be reinjected into the reservoir to maintain pressure and maximize liquids recovery. The Alen facilities are designed to process up to 440 MMcf/d of natural gas and 40 MBbl/d of condensate. We are the technical operator of the Alen Project.

Alen is progressing ahead of schedule and below budget. The total gross development cost is trending below sanction cost of $1.4 billion with first production currently expected during the third quarter of 2013 at 18 MBbl/d, net. The sanctioned plan originally scheduled commencement late fourth quarter of 2013. Significant effort has been placed to remove the risk from the schedule by completing as much of the field work as possible early in development. The wells are drilled and completed, the well-protector and jacket are installed, and the flowlines are in place. The final infrastructure, the topsides for the well-protector platform and the central platform, are expected to arrive in West Africa late March 2013 to begin installation.

Other Block O & I Projects We are continuing our exploration and appraisal efforts offshore Equatorial Guinea, where we still have numerous opportunities. We continue the appraisal program for our Carla and Diega discoveries, where we have encountered hydrocarbons in multiple appraisal wells and side-tracks.

During 2012, we identified a crude oil reservoir below the Alen field while drilling additional Carla appraisal wells. Development plans are being prepared for possible sanctioning of Carla during 2013, which would have a target first production at 11 MBbl/d, net, in early 2016. Carla further demonstrates the value of the infrastructure we are building that allows us to have host facilities and tie back additional fields.

We are continuing to review drilling results from our Diega discovery wells, finalizing an appraisal design program, and continue to evaluate regional development scenarios for the asset. We plan to begin appraisal drilling in the second half of 2013 or early 2014.

West Africa Gas Project We have a natural gas development team working with the Equatorial Guinea Ministry of Mines, Industry and Energy in evaluating several monetization options for natural gas that would be produced from Blocks O and I.

Cameroon We have an interest in over one million gross acres offshore Cameroon, which include the YoYo mining concession and Tilapia PSC. We are the operator (50% working interest) in Cameroon. Natural gas and condensate were discovered in 2007 when we drilled the YoYo-1 exploratory well. During 2012, we drilled the Trema exploration well testing the Tilapia Block, offshore Cameroon, but did not locate commercial quantities of hydrocarbons. We are currently evaluating prospects as a follow-up for our offshore Cameroon exploration program.

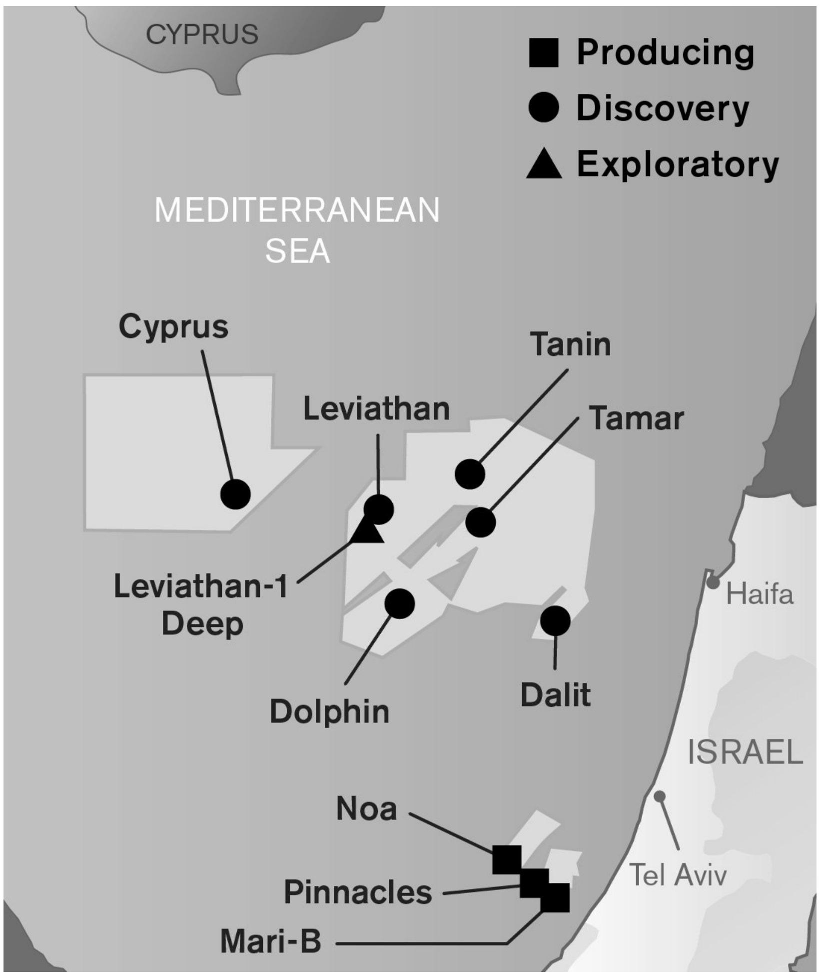
Sierra Leone During 2012, the Government of Sierra Leone awarded us participation in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million gross acres. Under the terms of the award, Chevron (SL) Ltd. will be the operator and we will have a non-operated 30% working interest. We plan to begin acquiring 2-D seismic information over portions of the acreage in 2013 to assist with our 3-D seismic plans. See Item 1A. Risk Factors - *Our entry into new exploration ventures in areas in which we have no prior experience subjects us to additional risks.*

Senegal/Guinea-Bissau During 2011, we farmed into the AGC Profond block (30% non-operated working interest) and the joint venture drilled the Kora-1 exploration well. The well did not result in commercial quantities of hydrocarbons. During 2012, we decided not to participate in the second appraisal period and relinquished our acreage. The cost associated with the undeveloped leasehold was charged to exploration expense in third quarter 2012.

Eastern Mediterranean (Israel and Cyprus) Another core operating area is located in the Eastern Mediterranean, where we have had six consecutive natural gas discoveries in recent years. We are also beginning to explore for potential thermogenic (crude oil generating) hydrocarbon systems which may exist at greater depths.

Israel, the only producing country in our Eastern Mediterranean segment, accounted for 7% of 2012 total consolidated sales volumes and 32% of total proved reserves at December 31, 2012. At December 31, 2012, we held approximately 58,000 net developed acres and 581,000 net undeveloped acres located between 10 and 90 miles offshore Israel in water depths ranging from 700 feet to 6,500 feet. Our leasehold position in Israel includes four leases and 13 licenses, and we are the operator of the properties. We also hold a license covering approximately 596,000 net undeveloped acres offshore Cyprus adjacent to our Israel acreage.

Locations of our operations in the Eastern Mediterranean are shown below:



Domestic Natural Gas Demand As the Israeli economy continues to grow, so does the demand for natural gas, which is currently 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 therefore willing to make the capital investment necessary to convert facilities to use natural gas. We expect that government requirements for emissions reductions could also drive demand for natural gas as fuel.

Natural Gas Export As discussed below, we have made significant natural gas discoveries in the Eastern Mediterranean. Although we continue to conduct appraisal activities, we expect that the quantity of natural gas discovered can be used to satisfy growing domestic demand as well as provide sufficient resources for export. Eastern Mediterranean export projects would be well positioned to supply growing global natural gas demand, and, as discussed further below, we are considering multiple options. The government of Israel is in the process of finalizing an export policy. See Regulations - *Israeli Interministerial Committee*, below.

Tamar Natural Gas Project We discovered the Tamar natural gas field (36% operated working interest), offshore Israel, in the Levant Basin in 2009. Tamar is one of the world's largest offshore conventional gas discoveries in recent years and is currently one of our major development projects. We expect first delivery of gas to customers in April 2013, four years from discovery and two and a half years from project sanction.

Tamar Phase 1 development includes five subsea wells with a combined production capacity of 985 MMcf/d, with identified expansion capability to approximately 1.5 Bcf/d. The natural gas produced at these wells will flow to a new offshore platform constructed near the existing Mari-B platform. The natural gas will then be delivered to the existing pipeline that connects the Mari-B field to the Ashdod onshore terminal. Tamar's 93-mile tieback, originating in a water depth in excess of 5,000 feet, is the longest subsea tieback in the world.

The Tamar partners have executed numerous gas sale and purchase agreements (Tamar GSPAs) for the initial and expanded capacity as well as a condensate sales agreement. See International Marketing Activities and Delivery Commitments below. In addition, a floating LNG (FLNG) project is under evaluation.

Leviathan Natural Gas Project In December 2010, we announced a significant natural gas discovery at the Leviathan-1 well (39.66% operated working interest) 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. The Leviathan-2 well was plugged due to wellbore issues. In 2012, we drilled the successful Leviathan-3 appraisal well and spud the Leviathan-4 appraisal well.

We have project and commercial teams in place and are in the process of screening multiple development concepts. Due to Leviathan's size, full field development and realization of maximum economic value is expected to require several development phases.

The Leviathan Phase 1 development concept includes offshore processing at an FPSO, with a production capacity of 1.6 Bcf/d and a capability to serve both domestic demand and export. Domestic production could begin as early as 2016. This option will enable us to begin production within three years of license to lease conversion. Phase 2, an additional FPSO, is expected to have a similar production capacity and capability.

Multiple export options, including onshore LNG, FLNG and pipeline 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 On December 2, 2012, we and our existing partners in the Leviathan project announced that we had agreed in principle on a proposal to sell a 30% working interest in the Leviathan licenses to Woodside Energy Ltd. Each of the current Leviathan partners is expected to participate as a seller to Woodside. We expect to convey a 9.66% working interest, reducing our working interest to 30%, and continue as upstream operator. The transaction is subject to the negotiations and execution of definitive agreements between the parties, as well as customary approvals, prior to closing.

According to the initial proposal, we would receive net cash payments totaling $464 million, a portion of which would be paid only upon the occurrence of certain future events. The payments, subject to definitive agreement, include the following:

- $287 million initial cash payment payable at closing;
- $64 million contingent on the ability to export natural gas; and
- $113 million contingent on a final investment decision for an LNG project.

Additional payments, subject to definitive agreement, would include the following:

- a share of Woodside's annual LNG revenue above certain price parameters, subject to a $322 million cap over the life of the project; and
- a drilling carry of up to $16 million on the drilling of the planned Mesozoic oil exploration well.

Including the potential revenue sharing amounts and drilling carry, the implied price for our 9.66% working interest being sold totals $802 million under the initial proposal. Negotiations continue, and, as a result, this amount could change. We expect to execute a final agreement with Woodside during the first half of 2013. In conjunction with these negotiations, we are assisting our current Leviathan partners to obtain appropriate financing for their share of development costs and considering providing a limited amount of financial backstop to them.

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 well pressure 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 will integrate the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically to test the deep oil concept. We have entered into a contract for drilling services to be provided by the Atwood *Advantage* drillship, which will be rated for operations in 12,000 feet water depth/40,000 feet drill depth with the capabilities necessary to reach the target objective, and plan to begin drilling an exploratory well in the fourth quarter of 2013.

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. Through December 31, 2012, we have delivered over 420 Bcf of natural gas, net, to Israeli customers.

During 2011, due to multiple interruptions in imported gas supplies from Egypt, Mari-B natural gas volumes were delivered at very high rates to support Israel's growing natural gas and power demands. As a result, the Mari-B field experienced accelerated depletion. In January 2012, we announced a cut back in production at Mari-B to prudently manage the reservoir. We have been working closely with our Israeli customers to manage demand on the Mari-B field and continue production from it.

In order to help meet Israeli natural gas demand until the Tamar field begins producing, we completed the Noa (47% operated working interest) and Pinnacles (47% operated working interest) wells and tied them back to the Mari-B platform. We began selling natural gas from Noa in June 2012 and Pinnacles in July 2012. At December 31, 2012, we recorded an impairment charge of $31 million for the combined Mari-B, Noa, and Pinnacles wells due to end-of-field life declines in production. See Item 8. Financial Statements and Supplementary Financial Data - Note 4. Asset Impairments.

We expect to continue producing from Mari-B, Noa and Pinnacles until production commences at the Tamar field. Once Tamar begins producing, Mari-B, Noa and Pinnacles production volumes will be reduced, and we plan to transition the Mari-B reservoir to a natural gas storage facility. We will continue to provide natural gas to Israeli purchasers under several natural gas sales and purchase agreements for which the total contract quantities have not been met. See Delivery Commitments and Item 1A. Risk Factors - *Exploration, development and production risks and natural disasters could result in liability exposure or the loss of production and revenues*.

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 Dolphin (39.66% operated working interest) and Tanin 1 (47.06% operated working interest) natural gas discoveries.

Cyprus During the fourth quarter of 2011, we made another natural gas discovery when we drilled the successful A-1 exploration well in Block 12, offshore Cyprus. We are planning to drill an appraisal well in 2013 and are working with the government of Cyprus on a domestic supply project as well as a potential LNG project. The Turkish government has voiced opposition to our drilling operations. However, the US and the European Union have expressed support for Cyprus' right to explore offshore for hydrocarbons in its exclusive economic zone.

Risks Although we will be able to incorporate major development project execution gained on the Aseng and Tamar projects to Leviathan or other LNG projects, such complex, costly projects as discussed above are not without financial or execution risk. See item 1A. Risk Factors - *The magnitude of our offshore Eastern Mediterranean discoveries will present financial and technical challenges for us due to the large-scale development requirements and 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.*

See also Item 1A. Risk Factors - *Our international operations may be adversely affected by economic and political developments* and *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.*

Other International

Our other international operations accounted for 2% of our total consolidated sales volumes for 2012 and 1% of total proved reserves at December 31, 2012.

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 acres, gross, located south and east of the Falkland Islands. The Falkland Islands are located in the South Atlantic Ocean approximately 400 miles from the South America mainland. The agreement was approved by the Falkland Islands Government in October 2012.

Under the agreement we have farmed-in to the Northern and Southern Area Licenses for a 35% working interest. FOGL will continue as operator until we assume operatorship of the Northern Area License in March 2013 and the Southern Area License no later than March 2014.

Our financial contribution includes 60% of the costs of two commitment wells and a $25 million cash contribution paid in January 2013. We may also elect to participate in a discretionary exploration well, paying 45% of the costs in return for a 35% working interest. We expect to invest approximately $180 to $230 million over the next three years.

During fourth quarter 2012, FOGL drilled the Scotia exploration well, which reached its Cretaceous objective in November 2012 and encountered 40 feet of net pay. We are encouraged by the well results. Although we did not see a substantial amount of the reservoir section, virtually all sandstones with significant porosity in and below the target contained hydrocarbons. We are currently evaluating the well results and have begun acquiring 3D seismic over the Northern and Southern Area licenses. The integration of these activities will allow us to assess the economic viability of this prospect. The Scotia well has been plugged in accordance with the regulations of the Falkland Islands Department of Mineral Resources, which require all exploration wells, including successful ones, to be plugged.

See Acquisition and Divestiture Activities - Entry into Falkland Islands Joint Venture and Item 1A. Risk Factors - *Our entry into new exploration ventures in areas in which we have no prior experience subjects us to additional risks*.

Nicaragua We continue to evaluate our undeveloped acreage and currently plan to spud our first exploration well (Paraiso), targeting a crude oil play, in the second half of 2013. A 3D seismic survey and further technical work have clarified this prospect and helped to decrease the risk. We are currently seeking a partner in this prospect, anticipating a working interest farmout by the time we spud the first exploration well.

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

North Sea We have been conducting business in the North Sea (the Netherlands and the United Kingdom (UK)) since 1996. During 2012, we sold our 30% non-operated working interests in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea. Also during the fourth quarter of 2012, the nearby Bligh well, a potential co-development candidate for our Selkirk discovery, was drilled. Bligh encountered hydrocarbons but disappointingly tight non-commercial reservoirs. Therefore, we determined that the Selkirk field was uneconomic for joint development and wrote it off to exploration expense. Our remaining North Sea assets are included in assets held for sale in our consolidated balance sheet as of December 31, 2012, and the North Sea geographical segment has been reported as discontinued operations in our consolidated statements of operations. See Item 8. Financial Statements and Supplementary Financial Data - Note 3. Acquisitions and Divestitures.

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;
- each field representing more than 1% of total proved reserves, as well as a selection of smaller fields, 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 Vice President – Strategic Planning, Environmental Analysis & Reserves (Vice President – Reserves) and certain members of senior management.

Our Vice President – Reserves is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Vice President – Reserves has a Bachelor of Science degree in Engineering and over 25 years of industry experience with positions of increasing responsibility in engineering and evaluations. The Vice President – Reserves reports directly to our Chief Executive Officer.

Technologies Used in Reserves Estimation The SEC's reserves rules expanded the technologies that a company can use to establish reserves. The SEC now allows 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 2012 reserves estimates.

Third-Party Reserves Audit In each of the years 2012, 2011, and 2010, we retained NSAI to perform reserves audits of proved reserves. The reserves audit for 2012 included a detailed review of eight of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 87% of US proved reserves and 98% of international proved reserves (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. The reserves audit for 2010 included a detailed review of 13 of our major fields and covered approximately 88% of total proved reserves.

In connection with the 2012 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, 2012, 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 Vice President – Reserves 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 each field representing more than 1% of total proved reserves, as well as a selection of smaller fields. The Tamar and Alen fields were first audited in 2010, and the Marcellus Shale field was first audited in 2011, as no reserves had been recorded in prior years.

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, 2012, on a quantity basis, the NSAI field estimates ranged from 26 MMBoe or 18% above to 1 MMBoe or 2% 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, 2012 were, in the aggregate, approximately 48 MMBoe, or 4%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2012, our PUDs totaled 159 MMBbls of crude oil, condensate and NGLs and 3,382 Bcf of natural gas, for a total of 723 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, 2012:

- 372 MMBoe in the Tamar field, offshore Israel, which will begin converting to proved developed at first production, currently expected in second quarter 2013;
- 158 MMBoe in the DJ Basin, including Wattenberg, consisting of 958 horizontal Niobrara locations, which is equivalent to less than three years of drilling based on current plans;
- 106 MMBoe in the Marcellus Shale, consisting of 290 horizontal locations, which is equivalent to less than three years of drilling based on current plans;
- 74 MMBoe in Equatorial Guinea, 64% of which are in the Alba field with the remainder in the Alen field. The Alba reserves, which will be recovered from existing wells with a sanctioned compression project, will be reclassified to proved developed at start-up, currently expected in 2016. The Alen PUDs will be reclassified to proved developed at start-up, currently expected in 2013;

- the above fields represent 98% of total PUDs. The remaining 2% is associated with ongoing developments in various areas scheduled in the next five years; and
- PUDs include no material amounts which have remained undeveloped for five years or more.

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

- recording of 135 MMBoe in the DJ Basin horizontal Niobrara program;
- partially offset by negative revisions of 94 MMBoe in the DJ Basin due to our decision to terminate the legacy vertical drilling program and focus capital and drilling rigs on the horizontal development of the Niobrara;
- recording of 51 MMBoe in the Marcellus Shale as a result of an ongoing development program with expansion into the wet gas area of the play;
- recording of an additional 7 MMBoe at Tamar as a result of ongoing appraisal work, plus 1 MMBoe from other international areas;
- conversion of 82 MMBoe into proved developed reserves, primarily related to ongoing development in the DJ Basin (19% of year-end 2011 PUDs converted) and Marcellus Shale (22% of year-end 2011 PUDs converted), the start-up of the Galapagos project in the deepwater Gulf of Mexico, and a pipeline pressure-reduction project in Equatorial Guinea;
- the sale of 3 MMBoe from our non-core asset divestiture program;
- positive revisions of 10 MMBoe, primarily due to increased recovery assumptions in the Marcellus Shale as a result of better than expected performance from existing wells; and
- negative revisions of 7 MMBoe, primarily in the Marcellus Shale, due to changes in commodity prices.

Development Costs   Costs incurred to advance the development of PUDs were approximately $1.8 billion in 2012, $1.4 billion in 2011 (including $66 million non-cash costs related to an increase in our Aseng FPSO lease obligation), and $1.1 billion in 2010 (including $266 million non-cash costs related to an increase in our Aseng FPSO lease obligation). A significant portion of costs incurred in 2012 related to our major development projects, horizontal Niobrara, Marcellus Shale, Alen and Tamar, which will be converted to proved developed reserves in future years.

Estimated future development costs relating to the development of PUDs are projected to be approximately $1.8 billion in 2013, $1.5 billion in 2014, and $1.1 billion in 2015. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. Proved undeveloped reserves 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 2017. PUDs associated with projects other than drilling (such as compression projects) are also expected to be converted to proved developed reserves prior to the end of 2017. Initial production from these PUDs is expected to begin during the years 2013 - 2017.

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, 2012, 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 (DOE). 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, 2012							
United States							
Wattenberg	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							
Wattenberg	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	
Year Ended December 31, 2010							
United States							
Wattenberg	19	151	10	$ 75.11	$ 3.95	$ 43.15	$ 3.62
Other US	20	249	4	74.95	4.31	36.23	7.91
Total US [4]	39	400	14	75.03	4.17	41.21	5.95
Alba Field (Equatorial Guinea) [2]	11	226	—	78.44	0.27	—	2.38
Mari-B Field (Israel)	—	130	—	—	4.03	—	1.15
Ecuador [5]	—	25	—	—	—	—	—
China	4	—	—	75.15	—	—	7.49
Total Consolidated Operations	54	781	14	75.76	2.98	41.21	4.39
Equity Investee [3]	2	—	5	77.98	—	53.68	
Total Continuing Operations	56	781	19	$ 75.83	$ 2.98	$ 44.90	

(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.

(4) Average crude oil sales prices reflect reductions of $1.32 per Bbl for 2010 from hedging activities. Average natural gas sales prices reflect a decrease of $0.01 per Mcf for 2010 from hedging activities. This price reduction resulted from losses that were previously deferred in AOCL. All hedge losses relating to US production had been reclassified to revenues by December 31, 2010.

(5) Includes sales volumes through November 24, 2010. Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales were eliminated for accounting purposes. Electricity sales are included in other revenues. See Exit from Ecuador above.

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, 2012, our operated properties accounted for approximately 72% 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, 2012 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	6,943	6,118.6	6,718	5,083.7	13,661	11,202.3
Equatorial Guinea	5	2.0	18	6.7	23	8.7
Israel	—	—	9	3.7	9	3.7
North Sea	9	1.2	9	1.1	18	2.3
China	27	15.4	1	0.6	28	16.0
Total	6,984	6,137.2	6,755	5,095.8	13,739	11,233.0

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, 2012 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore [(1)]	1,808	1,186	2,207	1,512
Offshore	96	41	500	373
Total United States	1,904	1,227	2,707	1,885
International				
Equatorial Guinea	285	119	180	80
Falkland Islands	—	—	9,921	3,472
Cameroon	—	—	1,084	542
Israel	124	58	1,333	581
Cyprus [(2)]	—	—	852	596
North Sea [(3)]	20	4	131	25
China	7	4	—	—
Sierra Leone	—	—	1,380	414
Nicaragua	—	—	1,855	1,855
India	—	—	694	347
Total International	436	185	17,430	7,912
Total	2,340	1,412	20,137	9,797

(1) Developed acres includes approximately 464,000 gross (214,000 net) in the Marcellus Shale that are held by the production of others.
(2) A portion of the acreage has been assigned to a partner and the agreement is awaiting government approval.
(3) The North Sea includes acreage in the UK and the Netherlands.

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:

	Year Ended December 31,					
	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US [(1)]	785	589	279	188	242	131
Deepwater Gulf of Mexico	42	20	29	20	42	37
Equatorial Guinea	—	—	307	137	—	—
Israel [(2)]	1,209	537	—	—	—	—
Cyprus [(3)]	852	596	—	—	—	—
Cameroon [(4)]	916	458	168	84	—	—
Total	3,804	2,200	783	429	284	168

(1) Represents acreage that will expire if no further action is taken to extend. Approximately 35% 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.

(3) Represents acreage that will expire if no further action is taken to extend. We are currently planning to drill an appraisal well in 2013. The result of this well will assist us in the evaluation of our acreage.

(4) The acreage in Cameroon is comprised of our Tilapia PSC and YoYo mining concession. Pursuant to the Tilapia PSC, our first exploration period expires on July 6, 2013; however, we have the right to extend our acreage for two additional periods of two years each. Pursuant to our YoYo mining concession, development must commence prior to December 2014; 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, 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
Year Ended December 31, 2010							
United States	4.8	1.9	6.7	510.6	1.0	511.6	518.3
Equatorial Guinea	—	—	—	2.0	—	2.0	2.0
Israel	—	—	—	1.0	—	1.0	1.0
North Sea	—	—	—	0.6	—	0.6	0.6
China	—	—	—	2.3	—	2.3	2.3
Total	4.8	1.9	6.7	516.5	1.0	517.5	524.2

In addition to the wells drilled and completed in 2012 included in the table above, wells that were in the process of drilling or completing at December 31, 2012 were as follows:

	Exploratory (1)		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	13	8.1	172	88.0	185	96.1
Cameroon	1	0.5	—	—	1	0.5
Cyprus	1	0.7	—	—	1	0.7
Equatorial Guinea	8	4.0	—	—	8	4.0
Falkland Islands	1	0.4	—	—	1	0.4
Israel	6	2.5			6	2.5
Total	30	16.2	172	88.0	202	104.2

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

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

Oil Spill Response Preparedness 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 exploration 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, 70 MBbl/d of liquids 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 a 15,000 psi-gauge intervention capping stack designed to shut-in wells in water depths to 10,000 feet, including extremely high-pressure, deeper wells in the deepwater Gulf of Mexico. We have entered into a separate utilization agreement with HESG which specifies the asset day rates should the HFRS system be deployed.

Internationally, we maintain membership in Oil Spill Response Limited (OSRL). OSRL is an industry owned cooperative which exists to ensure effective response to oil spills wherever they occur. OSRL is an industry leader in oil spill preparedness and response services. We also maintain agreements internationally with 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.

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.

International Marketing Activities Our share of crude oil and condensate from the Aseng field is sold to Glencore Energy UK Ltd (Glencore Energy) under a long-term sales contract at market rates and is transported by tanker. Natural gas from the Alba field is sold under a long-term 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. 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.

In Israel, we sell natural gas from the Mari-B, Noa and Pinnacles fields, and have contracted to sell natural gas from the the Tamar field, under long-term contracts. 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 at market-based prices.

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

Mari-B GSPAs We currently sell natural gas from the Mari-B, Noa and Pinnacles fields to several customers, including Israel Electric Corporation (IEC), under long-term Gas Sale and Purchase Agreements (Mari-B GSPAs). Due to end-of-field life declines in production from these fields, we will not be able to meet all contractual delivery commitments under the Mari-B GSPAs with reserves from these fields.

In January 2012, we issued force majeure notices to certain customers. The Mari-B GSPAs have customary liability cap language that limits our financial exposure in the event we cannot fully deliver the contract quantities. Our liability is 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 in the event that no production is available for delivery (subject to force majeure considerations). To date, these adjustments have totaled approximately $13 million, net. These sales price adjustments did not have a material impact on our earnings or cash flows.

As of December 31, 2012, a total of 218 Bcf, gross, (102 Bcf, net) remained to be delivered under the Mari-B GSPAs. In the fourth quarter of 2012, we and our Mari-B partners signed an agreement with IEC. The terms of the agreement provide for delivery of up to 100,000 MMBtu/d, gross, (47,000 MMBtu/d, net) of natural gas under the first IEC sales contract, once the Tamar field begins flowing, until the total contract quantity is fulfilled and, at the same time, termination of the second IEC sales contract. We have executed similar agreements with most of the other Mari-B gas purchasers.

At December 31, 2012, our remaining Mari-B, Noa, and Pinnacles proved developed reserves totaled approximately 17 Bcf, net, and will be used to satisfy our share of the Mari-B GSPAs on a pro-rata basis until the Tamar field begins producing. We expect that approximately 30 Bcf, net, of our Tamar proved reserves will be used to satisfy our share of contract quantities that remain to be delivered under the Mari-B GSPAs, as impacted by the recent agreements, when the fields cease producing. The majority of the quantities remaining under the Mari-B GSPAs are expected to be delivered over a three year period with one minor commitment extending over a 10-year period.

Tamar GSPAs As of December 31, 2012, we and our Tamar partners have entered into Gas Sale and Purchase Agreements (Tamar GSPAs) with the IEC and numerous other Israeli purchasers, including independent power producers, cogeneration facilities and industrial companies, for the sale of natural gas from the Tamar field. The Israeli government has approved the Tamar GSPAs.

The Tamar GSPAs include the following:

- sale of approximately 2.7 Tcf (approximately 1.0 Tcf net to us) of natural gas to IEC over an approximate 15-year period. IEC has the option to increase this amount to 3.5 Tcf (approximately 1.3 net to us), under certain conditions;
- sale of approximately 2.5 Tcf (approximately 0.9 Tcf net to us) of natural gas to additional customers. 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 are interruptible during certain contract periods; and
- sales prices based on an initial base price subject to price indexation over the life of the contract and with a floor. The IEC contract also provides for price reopeners in the eighth and eleventh years with limits on the increase/decrease from the contractual price.

Under the Tamar GSPAs, 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 (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.

At December 31, 2012, we have recorded 2.2 Tcf, net, of PUD reserves for the Tamar field. We expect to begin reclassifying these PUD reserves to proved developed at first production, currently expected in second quarter 2013. See International - Eastern Mediterranean (Israel and Cyprus) - *Tamar Natural Gas Project*.

Significant Purchaser Glencore Energy was the largest single non-affiliated purchaser of 2012 production and purchased our share of crude oil and condensate production from the Alba and Aseng fields in Equatorial Guinea. Sales to Glencore Energy accounted for 31% of 2012 total oil, gas and NGL sales, or 39% of 2012 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 Wattenberg area and internationally from the North Sea. Sales to Shell accounted for 14% of 2012 total oil, 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 2012. We believe that the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Hedging Activities Commodity prices were volatile in 2012 and prices for crude oil and natural gas are affected by a variety of factors beyond our control. We have used derivative instruments, and expect to do so in the future, 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. 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 is to hedge up to 50% of our forecasted domestic natural gas production and up to 50% of our total forecasted domestic and international crude oil production, for the current year plus two additional calendar years. We strive to maintain strong governance of our hedging program, including oversight by our Board of Directors. For additional information, see Item 1A. Risk Factors – *Commodity and interest rate hedging transactions may limit our potential gains* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments*, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Regulations

Government Regulation 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 and frequently increase the 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 and incremental cost 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 – *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.*

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 both 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 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 eliminates, inter alia, a previously enacted progressive reduction in the rate of corporate tax rate, and increases the corporate tax rate to 25%.

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 the Bureau of Safety and Environmental Enforcement (BSEE), which under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act, have certain authority over our operations on federal lands, 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.

The EPA has issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires many suppliers of fossil 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 begin collecting greenhouse gas (GHG) emissions data, beginning in 2012 for 2011 emissions, under a new reporting system that went into effect on January 1, 2010. The first annual report was due September 30, 2011. In November 2010, the EPA issued final regulations requiring the annual reporting of GHG emissions from qualifying facilities in the upstream oil and natural gas sector, including onshore production (Subpart W). Substantially all of our onshore US properties are subject to the Subpart W reporting requirements.

On April 18, 2012, the EPA issued regulations under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants. The new rules are related to emissions associated with crude oil and natural gas production, including natural gas wells that are hydraulically fractured. The required technologies and processes, while reducing emissions, will also 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 will 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 wells will be required to use green completions. The EPA's final rules have minimal impact on our business. The reduction of greenhouse gas emissions (GHG) 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've undertaken emission reduction projects such as our US Vapor Recovery Unit (VRU) program, where we have installed VRUs to capture 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. 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 is expected to approve and implement new setback rules for oil and gas wells and production facilities located in close proximity to occupied buildings. If the new setback rules are approved, the current COGCC setback distances of 150 feet in rural areas and 350 feet in high density urban areas will be increased to a uniform 500 feet statewide setback from occupied buildings and a uniform 1,000 feet statewide setback from high occupancy building units. The new setback rules would also require operators to utilize increased mitigation measures to limit potential drilling impacts to surface owners and the owners of occupied building units. The new rules would also 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. The new statewide rule requires 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. The revised rule for the GWA 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, Colorado Regulation Seven and requirements for storm water management plans were adopted by the Colorado Department of Environmental Quality, under delegation from the EPA, to regulate air emissions, water protection and waste handling and disposal relating to our oil and gas exploration and production.

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 completion, drilling, 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 decision from the Supreme Court is still pending, but a ruling upholding the lower court's decision could make it more difficult to develop our Marcellus 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 undesigned 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.

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 within which 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.

Israeli Interministerial Committee   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 prevent, but rather promotes the ensuring of the needs of domestic users and works to encourage 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 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.

We are participating in the process and monitoring the impact of the Committee's recommendations. However, at this time, we cannot predict the ultimate outcome of the Committee's recommendations or the possible impact any resulting laws or regulations could have on our business. Certain changes in Israel's market, fiscal, and/or regulatory regimes occurring as a result of the Committee's recommendations could delay or reduce the profitability of our Tamar and/or Leviathan development projects and render future exploration and/or development projects uneconomic.

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, contains significant derivatives regulation, including requirements that certain transactions be cleared on exchanges and that collateral (commonly referred to as “margin”) be posted for such transactions. The Dodd-Frank Act provides for a potential exception from these clearing and collateral requirements for commercial end-users, such as us, and it includes a number of defined terms 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 and Trading Commission (CFTC) has promulgated numerous rules to define these terms.

We have been evaluating the provisions of the CFTC's final rules and assessing their impact on our commodity hedging program. At this time, we believe that we will be able to satisfy the requirements for the commercial end-user clearing exception and continue to engage in transactions which hedge commercial risk and are free of mandated clearing requirements.

It is possible that the CFTC, in conjunction with 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 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.

The CFTC's final rules will also have an impact on our hedging counterparties. For example, our bank counterparties will be required to post collateral and assume compliance burdens resulting in additional costs. We expect that much of the increased costs will be passed on to us, thereby decreasing 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. See Item 1A. Risk Factors - *Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.*

Impact of Dodd-Frank Act Section 1504 Section 1504 of the Dodd-Frank Act required the SEC to issue rules requiring resource extraction issuers to include in an annual report information relating to any payment made by the issuer, a subsidiary of the issuer, or an entity under the control of the issuer, to a foreign government or the federal government for the purpose of the commercial development of oil, natural gas, or minerals. On August 22, 2012, the SEC issued a final rule, Disclosure of Payments by Resource Extraction Issuers (Rule). The Rule requires resource extraction issuers, such as us, to provide 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. The first report is due May 30, 2014.

In October 2012, the U.S. Chamber of Commerce, American Petroleum Institute, Independent Petroleum Association of America, and National Foreign Trade Council filed a lawsuit against the SEC in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners argued that the Rule is “arbitrary and capricious” within the meaning of the Administrative Procedure Act and that the Rule and statute violate the First Amendment. Briefs have been submitted. Oral arguments are not yet scheduled.

See Item 1A. Risk Factors - *Disclosure of certain operating information as required by Section 1504 of the Dodd-Frank Act could have a negative impact on our operations.*

See also Item 1A. Risk Factors - *Our operations may be adversely affected by changes in the fiscal regimes and government policies and regulation of oil and gas development in the countries in which we operate* for a discussion of the American Taxpayer Relief Act of 2012.

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 prior owners or operators in accordance with current laws or otherwise, 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. 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 – *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs*.

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, regulators and the general public. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment have been raised at all levels, including federal, state and local, as well as internationally. There have been claims that hydraulic fracturing may contaminate groundwater, reduce air quality or cause earthquakes. 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 for many years, 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); approximately 80% 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 implementing a pilot water recycling program. In the Marcellus Shale, our joint development agreement with CONSOL provides us with access to water resources which we believe will be adequate to execute our development program, and we engage in recycling efforts. We believe that these processes help ensure that hydraulic fracturing does not pose a meaningful risk to water supplies.

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 was charged with making recommendations to improve the safety and environmental performance of hydraulic fracturing. On August 18, 2011, the Subcommittee issued its Ninety Day Report (Report), which focused exclusively on the production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee identified four primary areas of concern including possible water pollution, air pollution, disruption of the community during production, and potential for adverse impact on communities and ecosystems. The Subcommittee also set forth a list of recommendations addressing, among other areas, communications, air quality, 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. The Subcommittee issued its Final Report in November 2011 which recommends implementation of the Subcommittee's recommendations by federal and state agencies. We continue to monitor the impact the Subcommittee's recommendations, and any resulting rule-making activities evolving at federal and state levels, could have on our exploration and development activities in shale formations.

During 2012, the BLM proposed regulations governing hydraulic fracturing on federal lands. The regulations would require: (1) public disclosure of chemicals used in hydraulic fracturing operations; (2) assurances on well-bore integrity to verify that fluids used in wells during fracturing operations are not escaping; and (3) confirmation of a water management plan in place for handling fracturing fluids that flow back to the surface. On January 21, 2013, the BLM announced that it was withdrawing its proposed regulations and would reissue a new set of proposed regulations regarding hydraulic fracturing later in 2013.

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 draft guidance outlines for EPA permit writers, where EPA is the permitting authority, requirements for diesel fuels used for hydraulic fracturing wells, technical recommendations for permitting those wells, and a description of diesel fuels for EPA underground injection control permitting.

The EPA is 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 addition, the EPA's recently-issued proposed rules subjecting oil and gas operations to regulation under the New Source Performance Standards will be applicable to newly drilled and fractured wells as well as existing wells that are refractured.

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, the City of Longmont, Colorado voted 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. COGA also separately sued the City of Longmont claiming that the resolution is a taking of the mineral property rights and an improper regulatory impairment of such rights, that it is effectively an illegal ban on drilling, and otherwise asserting that the ban must be set aside since it conflicts with Colorado state law allowing the practice.

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, under which companies are required to provide a listing of chemical ingredients used to hydraulically fracture wells that are permitted by the RRC on or after February 1, 2012 on a public national chemical disclosure registry, FracFocus.org, 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 – *Federal or state hydraulic fracturing legislation could increase our costs or restrict our access to oil and gas reserves;*
- Item 1A. Risk Factors – *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*;
- Item 1A. Risk Factors – *We face various risks associated with the trend toward increased anti-development activity*; 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 continuous effort.

We begin by leasing acreage (or deepwater lease blocks) from individuals, other operators or the federal government. It may take years for us to assemble enough 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 locate a drilling rig with the specifications for the depth and pressure situation in which we will drill.

For example, several years ago, we wanted to leverage our expertise in the Wattenberg area to open a new opportunity in Northern Colorado. We began acquiring acreage spanning an area from the edge of the GWA to the Wyoming border. It took over two years to assemble enough acreage through acquisition and leasing to have a significant enough acreage position to warrant data collection. Once the acreage position had been established, we conducted an extensive 3D seismic program and obtained other data as well, which our exploration staff analyzed and used to plan an initial drilling program.

After drilling an exploratory well, 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.

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, and make an investment decision. 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 high level of drilling activity, drilling rigs and hydraulic fracturing crews are in high demand, and there could be substantial delays as we wait for rigs or crews to become available.

In Northern Colorado, our data collection efforts resulted in a successful initial drilling program. Due to the success of our first wells, we have continued the Northern Colorado drilling program and, in 2012, we drilled 25 development wells.

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

Geographical Data

We have operations throughout the world and manage our operations by country. 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 17. Segment Information.

Employees

Our total number of employees increased 17%, from 1,876 at December 31, 2011 to 2,190 at December 31, 2012, in support of our major development and exploration projects. The 2012 year-end employee count includes 203 foreign nationals working as employees in Israel, the UK, Equatorial Guinea, Cyprus, and Cameroon. We regularly use independent contractors and consultants to perform various field and other services.

Offices

Our principal corporate office is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. We maintain additional offices in Ardmore, Oklahoma; Denver, Colorado; Greeley, Colorado; and Canonsburg, Pennsylvania; and in China, Cameroon, Equatorial Guinea, Israel, Cyprus, Nicaragua, and the UK.

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.

Butler vs. Powers On September 7, 2011, an intermediate appellate court (Superior Court) in Pennsylvania issued an opinion in *Butler v. Powers* regarding the interpretation of a deed. As a result, traditional views of how ownership of shale gas is determined in that state have been called into question. The issue raised by the case is whether shale gas is different from other natural gas and should be considered part of mineral rights, rather than oil and gas rights, because shale gas is contained inside unconventional shale rock. An appeal of the decision was subsequently filed with the Pennsylvania Supreme Court, which decided to hear the appeal. Written and oral arguments in the case have been presented and the parties are awaiting the decision of the Court.

At this time, no case law or interpretation of existing law has changed, nor has there been an indication that either the Superior Court or the Pennsylvania Supreme Court will seek to change existing law. Based upon our initial review, we believe that any adverse decision in the pending case would have minimal adverse impact upon the assets acquired from CONSOL and our Marcellus Shale joint venture operations.

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. We continue to examine some of our Marcellus Shale leases and fee interests for potential title defects. 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 confer to the holder 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, a robust global compliance program, 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, and cash flow at risk (CFAR) analysis. 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 – Investors Menu – 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. On October 25, 2011 our Board approved and adopted a revised Code of Business Conduct and Ethics. Copies of the revised Code of Business Conduct and Ethics, 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, 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 2012 were as follows:

	Daily Average Settlement Price for Prompt Month Contracts	
	High	Low
Year Ended December 31, 2012		
NYMEX		
Crude Oil - WTI (Per Bbl)	$ 109.77	$ 77.69
Natural Gas - HH (Per MMBtu)	3.90	1.91
Brent		
Crude Oil (Per Bbl)	126.22	89.23

Prices for our NGL production are determined at two primary market centers, Conway and Mt. Belvieu. For the year ended December 31, 2012, our consolidated net realized NGL prices were approximately 37% of consolidated net realized crude oil prices and tended to track the volatility of NYMEX WTI.

The 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;
- 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 and natural gas;
- 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;
- the potential expansion of 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;
- impact of conservation efforts on the ability to access government-owned and other lands for exploration and production activities; and
- domestic and foreign governmental regulations and taxes.

Declines in commodity prices or lack of natural gas storage may have the following effects on our business:

- reduction of our revenues, operating income and cash flows;
- curtailment or shut-in of our natural gas 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;
- cause certain properties in our portfolio to become economically unviable;
- cause us to delay or postpone some of our capital projects, including our horizontal Niobrara and Marcellus Shale, deepwater Gulf of Mexico, or international development projects;
- cause significant reductions in our capital investment programs, resulting in a reduced ability to develop our reserves;
- limit our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations; and
- limit our access to sources of capital, such as equity and long-term debt.

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

- asset impairment charges resulting from reductions in the carrying values of our oil and gas properties at the date of assessment, such as occurred in 2012, 2011, and 2010;
- additional counterparty credit risk exposure on commodity hedges; or
- a 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, limitation of our growth and 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. Gunflint, Big Bend, Leviathan, Cyprus, Carla and Diega are being appraised and, as such, not yet sanctioned, and 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 complexity, including extensive 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 infrastructure. In addition, we have expanded our horizontal drilling programs in the Niobrara formation and Marcellus Shale.

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 have increased dependency 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 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 could adversely affect project development;
- lack of government approval for projects;
- civil disturbances, anti-development activities, legal challenges or other 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 40% of our 2012 total consolidated sales volumes coming from international areas. This will be increasing as major development projects offshore West Africa and the Eastern Mediterranean begin producing in 2013. 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 recommendations of Israel's Interministerial Committee to Examine Government Policy on Israel's Natural Gas Economy (Interministerial Committee), 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 foreign hydrocarbon-producing nations, such as expropriation or nationalization of assets or termination of contracts, such as the termination of our Block 3 PSC by the Ecuadorian government in 2010 pursuant to changes in Ecuador's hydrocarbon law;
- disruptions caused by territorial or boundary disputes in certain international regions, including the Eastern Mediterranean, where Lebanon has made claims related to our projects in Israeli waters and the Turkish government in Ankara objected to exploratory activities conducted offshore the Republic of Cyprus;
- changes in drilling or safety regulations in other countries as a result of the Deepwater Horizon Incident or other incidents that have occurred, such as offshore Brazil and in China's Bohai Bay, which could increase costs and development cycle time;
- 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, such as Israel; 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 exploration activities, such as in the Eastern Mediterranean, offshore Nicaragua, or the Falkland Islands. Large discoveries, such as ours in the Levant Basin, may have impacts on global natural gas supplies.

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

Our operations may be adversely affected by changes in the fiscal regimes and government policies and regulation of oil and gas development in the countries in which we operate.

Fiscal regimes impact oil and gas companies through laws and regulations governing royalties, taxes, resource access, or level of government participation in oil and gas projects. 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 take, and a corresponding decrease or increase in the revenues of an oil and gas company operating in that particular country. For example, the Petroleum Profits Taxation Law, 2011, imposed additional income tax on oil and gas production in Israel. A large portion of our production comes from Equatorial Guinea; therefore, changes in its fiscal regime could have a significant impact on our operations. In addition, we cannot predict how government agencies or courts will interpret existing tax laws and regulations or the effect such interpretations could have on our business.

Many countries are currently experiencing fiscal problems and sustained structural government budget deficits and lower tax revenues triggered by the lingering effects of the global economic crisis of 2008, associated recession and current slower economic growth rates. Higher unemployment and slower growth rates, coupled with a reduced tax base, have resulted in reduced government revenues, while government expenditures continue to grow due to the costs of entitlements, subsidies and economic stimulus programs. Many countries have generated significant budget deficits and sovereign debt levels with some approaching insolvency. Demands on certain governments to undertake austerity measures in response to the European debt crisis have resulted in increased social unrest. In addition, certain non-governmental organizations are promoting "tax fairness", "fair share" payments, and income redistribution. Regulations enacted to achieve "tax fairness" or income redistribution could result in increased tax burdens on individuals or corporations.

Due to pressures from financial markets or local constituents to address these negative fiscal situations and initiate deficit reduction measures, many governments are seeking additional revenue sources, including increases in government take from oil and gas projects.

In the US, on January 2, 2013, the President signed into law The American Taxpayer Relief Act of 2012 (the Act). The Act extended through 2013 certain expired and expiring business tax provisions, including the research credit, bonus depreciation and others. However, the Act did not settle the debate on deficit reduction as the bill delayed mandatory across-the-board spending cuts known as sequestration, nor did it address increasing entitlement costs and fundamental tax reform. In recent years, certain measures have been proposed that would alter current tax expense on oil and gas companies through: 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 taxes on the oil and gas industry will continue to be reviewed by the US Congress in 2013 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 current deductibility of IDC expenditures would impact our cash available for investment and could curtail our domestic capital spending program by 15 - 25%.

In addition, although Congress recently passed, and the President signed into law, a bill that suspended the debt ceiling until May 19, 2013, the long-term debt ceiling and federal budget deficit issues must be resolved. Congress must pass new legislation and the President must sign it into law in order to avoid or mitigate these situations. At this time, substantial uncertainty exists as to whether or how these matters will be resolved. Certain measures, if enacted too suddenly, could reduce economic growth and increase the risk of a recession.

Changes in fiscal regimes have long-term impacts on our business strategy, and uncertainty makes it more difficult to formulate capital investment programs. The implementation of new, or the modification of existing, laws or regulations impacting the amount of government take could disrupt our business plans and negatively impact our operations in the following ways, among others:

- restrict resource access or 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 project 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 current 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;
- 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 and destruction of property 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 including:

US and Europe Within the last decade, violent acts have occurred which specifically targeted citizens and property of the US and other Western nations including the September 11, 2001 World Trade Center attack, the 2004 Madrid train bombing, the 2005 attack on London's public transportation system, and the 2012 attacks on US embassies in Libya, Egypt and Yemen. Attacks on Western citizens and property occur not just on US and European soil, but worldwide.

West Africa In the countries of West Africa there have been numerous acts of piracy, kidnapping, civil strife, regional conflict, cross-border violence, war, as well as violence associated with corruption, drug trafficking and regime changes. For example, in January 2013, numerous workers at a natural gas facility in Algeria were taken hostage and some were killed. In 2012, the government of Mali asked the United Nations to aid its defense against armed rebels. Also in 2012, militants in Nigeria continued their attacks on residents and property, and engaged in cross border attacks into Cameroon. In addition, deadly labor violence occurred in South Africa. Violence, loss of life and property damage associated with piracy in the Gulf of Guinea have impacted several countries of West Africa as well as the international community.

Middle East Civil unrest, often accompanied by violence, has spread throughout the region. Protesters have demanded economic and political reforms, and to date, there have been several regime changes. Civil unrest could continue to spread throughout the region or grow in intensity, leading to regime changes resulting in governments that are hostile to the US, civil wars, or regional conflict.

There have also been rising international tensions over Iran, which was censured by the United Nations over its nuclear development activities. Certain countries have implemented economic sanctions and/or considered pre-emptive strikes on suspected nuclear sites. Iranian officials have threatened retaliation by, among other actions, closing the Strait of Hormuz, through which a significant portion of the global crude oil supply is transported.

In November 2012, Israel and the Hamas militant group were engaged in air strikes and rocket attacks resulting in civilian deaths. Although a cease-fire is currently in effect, some level of conflict is likely to continue. In December 2012, the Turkish-Syrian border became militarized; US and Dutch NATO troops were deployed to defend against the perceived threat of a Syrian missile attack, possibly with chemical weapons.

Central America There have been numerous acts of violence associated with drug trafficking and constant military and police operations targeting organized crime. The existence of autonomous regions in Nicaragua could increase instability or conflict with the central government.

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 complete disruption of our business activities; and
- capital market reassessment of risk and subsequent reallocation of capital to more stable areas making it more difficult for 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 85% of our current production, each of our major development projects, and most of our exploration potential. During 2012, we initiated a non-core divestiture program to high-grade and focus our portfolio, and sold certain non-core onshore US and North Sea assets.

As a result of these portfolio changes, our operations and production are concentrated in fewer areas, and more of our production is from fewer wells. For example, approximately 20% of our 2012 production came from four offshore developments. Although, individually, none of these core areas represent more than 33% of our 2012 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 greater impact on our production profile, cash flows and overall business plan than if we operated in a larger number of areas.

We do not maintain business interruption (loss of production) insurance for all of our assets. Loss of production or limited 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 risks and natural disasters 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 hydraulic fracturing operations;
- security breaches, cyber attacks, piracy, or terroristic acts;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity such as the DJ Basin and Marcellus Shale;
- hurricanes, cyclones, windstorms, or "superstorms", such as Hurricane Sandy which occurred in 2012, 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 Rocky Mountain areas;
- unseasonably warm weather, which could affect third party gathering and processing facilities, such as occurred in the Rocky Mountain areas during 2012;
- volcanoes which could affect our operations offshore Equatorial Guinea;
- flooding which could affect our operations in low-lying areas such as the Marcellus Shale;
- 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, such as Gunflint, Alen, Tamar, or Leviathan, 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 forecast production, which could prevent the realization of our targeted return on capital or lead to unexpected future losses.

Deepwater frontier areas, especially in international locations such as offshore the Falkland Islands, Nicaragua or Sierra Leone, may lack the equipment and services necessary for rapid subsea intervention, containment, capture and shut-in capacity in the case of a well accident or spill. Spill containment and cleanup activities are costly. In addition, the resulting regulatory costs, civil or criminal fines or sanctions, results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity about us, could well exceed the actual costs of containment and cleanup. As a result, a well spill or accident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity and financial position.

Many offshore areas are subject to hazardous conditions, such as harsh weather and rough seas offshore the Falkland Islands or hurricanes in the Gulf of Mexico, which can limit certain exploration or development activities or increase the risk of accident.

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 on which we are moving forward. 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 such as the Marcellus Shale, Gunflint, Leviathan or Cyprus Block 12, 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 special technology for development drilling or well completion and we may not have the knowledge or expertise in applying new technology. Our efforts may result in a dry hole or a well that finds noncommercial quantities of hydrocarbons. Development drilling has the same legal and physical 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 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, in areas of high activity and demand in which we concentrate, such as the DJ Basin and the Marcellus Shale, we may experience delays in obtaining well completion rigs and services. 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.

Our operations could be adversely affected by future changes in laws and regulations which may occur as a result of the Deepwater Horizon Incident and other recent incidents.

In recent years, several oil spills have highlighted the dangers associated with exploration and production activities in deepwater. In 2010, the drilling rig Deepwater Horizon sank after a blowout and fire. The resulting leak caused a large oil spill in the Gulf of Mexico. In 2011, leaks attributed to exploration and production activities occurred offshore the coasts of Brazil and Nigeria and in China's Bohai Bay. In 2012, several workers were injured and some were missing and presumed dead as the result of a fire that erupted on an oil platform in the shallow water Gulf of Mexico, and a drilling rig being towed offshore Alaska broke away from the tugboat and ran aground.

In the US, the legislative and regulatory response to the Deepwater Horizon Incident is ongoing. In 2010, the US Department of the Interior issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability. In January 2011, the President's National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps. In 2011, the European Commission recommended that new legislation be enacted to enhance the safety of offshore oil and gas activities and, in 2012, established the European Union Offshore Oil and Gas Authorities Group.

In the US, additional regulatory review, slower permitting processes and increased oversight have resulted in longer development cycle time for our deepwater Gulf of Mexico projects. Cycle time is the length of time it takes for a project to progress from first discovery to first production, and longer development cycle times could result in lower rates of return on our investments.

Increased regulation impacting our activities in the Gulf of Mexico and other deepwater areas could result in extensive efforts to ensure compliance and incremental compliance costs. A significant delay or cancellation of our planned Gulf of Mexico deepwater exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our long-term production profile with a negative impact on our operating results and cash flows.

There have also been discussions regarding the establishment of a new industry mutual response fund in which companies would be required to participate and which would be available to pay for clean up and consequential damages arising from an oil spill.

Other countries are also considering additional regulation. In the European Union there have been demands for temporary bans on new deepwater drilling and/or additional safety regulation.

Future legislation or regulation is also likely to result in substantial increases in civil or criminal fines or sanctions. Such fines or sanctions could well exceed the actual cost of containment and cleanup associated with a well incident or spill. Governmental fines or penalties could also be excessive.

We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Deepwater Horizon Incident and other oil spills and accidents is not yet known. 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 in the deepwater Gulf of Mexico or other locations, 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.

The magnitude of our offshore Eastern Mediterranean discoveries will present financial and technical challenges for us 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 require 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. In December 2012, we and our existing partners in the Leviathan project announced that we had agreed in principle on a proposal to sell a 30% WI in the Leviathan licenses to Woodside Energy Ltd. (Woodside). The transaction is subject to the negotiations and execution of definitive agreements between the parties, as well as customary approvals, prior to closing. Failure to reach a definitive agreement with Woodside could result in a delay in the Leviathan development project.

In Israel, the Interministerial Committee, which was charged with the task of proposing a government policy for developing the natural gas economy in Israel, issued its final report in 2012. We are monitoring the activities of the Interministerial Committee to assess the possible impact, positive or negative, of any resulting laws or regulations on our business. Certain changes in Israel's market, fiscal, and/or regulatory regimes occurring as a result of Interministerial Committee recommendations could delay or reduce the profitability of our Tamar and/or Leviathan development projects and render future exploration and development projects uneconomic.

The Israeli Antitrust Commissioner has been reviewing Israel's domestic natural gas sales and ownership in offshore blocks and leases. He has publicly expressed concerns regarding ownership concentration on exploration blocks and development projects and its potential impacts on a competitive domestic natural gas price environment and end user electricity costs. We have cooperated with the Commission's review and, at this time, cannot predict the outcome.

Restrictions on resource access or controls over 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 result in damage to our reputation, limit growth in value 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 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 partners' available cash flows or impair their ability to obtain adequate project 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 traditional sources of funding or make funding more expensive; and
- regional conflict, which could result in capital market reassessment of risk and withdrawal of capital to more stable areas.

If these issues occurred and impacted our project partners, it could result in a delay or cancellation of a project, resulting in our inability to replace reserves and budgeted 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 (OECD) 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 greater import or export restrictions. In addition, the US government imposes economic and trade sanctions against certain foreign countries and regimes, such as Iran and Syria. 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 certain areas, law enforcement may be more robust and enhanced 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 impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

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 a potential 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 and Trading Commission (CFTC) has promulgated numerous rules to define these terms.

In addition, it is possible that the CFTC, in conjunction with 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 negotiated credit thresholds above which an end-user must 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 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 when there are changes in the underlying commodity prices or interest rates that are referred to in these contracts.

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.

Disclosure of certain operating information as required by Section 1504 of the Dodd-Frank Act could have a negative impact on our operations.

On August 22, 2012, the SEC issued final rules: Disclosure of Payments by Resource Extraction Issuers (Final Rules), as required by the Dodd-Frank Act. As a result, beginning in 2014, we must provide 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. If these required disclosures conflict with the confidentiality obligations of our subsidiaries or the general laws of the respective countries in which they operate, there could be substantial negative impacts on our operations. Disclosure of certain information could have the following negative impacts, among others, on our operations:

- compromise of the security of our employees by subjecting them to detention, arrest, claims of espionage and/or prosecution;
- loss of our license to operate in countries where the laws and regulations or terms of production sharing or other contracts prohibit disclosures of certain information, resulting in a reduction in our profitability;
- decrease in our ability to compete for new sources of reserves with state-controlled national oil companies or large multi-national companies not subject to disclosures under the Final Rules; and
- reduction in profitability and cash flows and a decrease in the price of our common stock.

We face various risks associated with global populism.

Due in part to the upheaval and uncertainty caused by global economic events including the financial crisis and resulting recession that began in 2008, higher unemployment, and government austerity measures, populist sentiments have risen. Populism is directed against perceived economic and social inequality. During 2012, workers across the European Union, including Spain, Portugal, Greece and Belgium, engaged in strikes and demonstrations to protest cuts in government spending, pensions and entitlements and increases in taxes. In many situations, social media channels have been used to organize protesters and increase public participation.

Certain political and non-governmental organizations are promoting "tax fairness", or "fair share". "Tax fairness" claims to create a fair, clear and equivalent tax system for all taxpayers by limiting legislation and rules that benefit one segment of the tax-paying population over another. However, the impact of such changes could be the loss of business incentives and/or increased taxes for individuals or corporations.

Populist activities could result in the following:

- increased regulation of our business;
- increased regulation of the banking industry; and
- increased corporate income taxes.

Our need to incur costs associated with responding to these developments or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, 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 operations.

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

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry, such as us, are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental compliance, transparency, anti-corruption, and business practices.

Anti-development activists are working to, among other things, reduce access to national and state government lands; delay or cancel certain projects such as offshore drilling, shale development, and pipeline construction; limit or ban the use of hydraulic fracturing; or block activity in sensitive environmental areas such as the Arctic. For example, in 2012, the City of Longmont, Colorado voted to ban hydraulic fracturing activities within city limits. Environmental activists have challenged decisions to grant air-quality permits for offshore drilling and have advocated for increased regulations on shale drilling and hydraulic fracturing in the US. Activists have recently attempted to prevent exploratory drilling in the Arctic.

Activities engaged in by some non-governmental organizations seeking to increase revenue transparency, limit foreign government corruption, increase "tax fairness" or "fair share" payments, or promote income redistribution could result in regulatory changes which could increase our taxes and decrease our profitability.

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

Future activist efforts could result in the following:

- delay or denial 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 us;
- 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 resulting 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 application 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 and for many 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 complexity of the technologies needed to extract oil and gas in increasingly difficult physical environments, such as deepwater, ultra-deepwater and shale, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. For example, in 2012, a wave of network attacks impacted Saudi Arabia's oil industry and breached financial institutions in the US. Certain countries, including China, Russia and Iran, are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies. SCADA-based systems are potentially more vulnerable to cyber attacks due to the increased number of connections with office networks and the internet.

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.

Although to date we have not experienced any material losses relating to cyber attacks, there can be no assurance that we will not suffer such losses in the future. 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 or state hydraulic fracturing legislation could increase our costs or restrict our access to oil and gas reserves.

Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. In past Congresses, several bills were filed that, if implemented, would have subjected all hydraulic fracturing to regulation under the Safe Drinking Water Act. It is likely that similar bills will be introduced in the current Congress. Further, the EPA's Office of Research and Development (ORD) is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. Several states are considering legislation to regulate hydraulic fracturing practices, including restrictions on its use in environmentally sensitive areas. Some municipalities have significantly limited or prohibited drilling activities, or are considering doing so. For example, in November 2012, the City of Longmont, Colorado voted to ban hydraulic fracturing activities within city limits.

Although it is not possible at this time to predict the final outcome of the ORD's study or the requirements of any additional federal or state legislation or regulation regarding hydraulic fracturing, any new federal or 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 areas, could significantly increase our operating, capital and compliance costs as well as delay or halt our ability to develop oil and gas reserves. See Items 1. and 2. Business and Properties - Hydraulic Fracturing.

The marketability of our DJ Basin, Marcellus Shale, 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 the DJ Basin, Marcellus Shale, 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. Although 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. Activist or other efforts may delay or halt the construction of additional pipelines or facilities.

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 oil and 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, such as recent changes in setback requirements expected to be approved by the COGCC, 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, such as the recent ban on hydraulic fracturing enacted by the City of Longmont, Colorado;
- landowner opposition to infrastructure development, such as recent landowner challenges to the use of eminent domain to gain access to land for the extension of the Keystone pipeline through Texas, or to onshore delivery points in Israel;
- regulation of federal land by the BLM, which has proposed rules for hydraulic fracturing on federally-owned land, and which can limit our access to a significant portion of our Nevada acreage;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, occupation of drilling sites, or damage to equipment;
- disputes regarding leases, such as the *Butler v. Powers* case in Pennsylvania; 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 in which we have no prior experience subjects us to additional risks.

During 2012, we entered into three new, high-potential areas, none of which currently has crude oil or natural gas production: Northeast Nevada, offshore the Falkland Islands, and offshore Sierra Leone. We are also planning to drill our first exploratory well offshore Nicaragua. These arrangements represent entry into new geographical areas in which we have no prior experience. Our activities will be subject to many 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, similar to that offshore the Shetland Islands in the North Sea, includes harsh weather and rough seas which could limit seismic and other exploration activities during certain periods; and
- there have been numerous acts of piracy, kidnapping, civil strife, regional conflict, cross-border violence, and war, as well as violence associated with corruption, drug trafficking and regime changes in the countries of West Africa which could disrupt our operations offshore Sierra Leone.

The people of the Falkland Islands have the right to self-determination, and the Falkland Islands is a United Kingdom Overseas Territory by choice. However, the government of Argentina persists in questioning its status. Actual or perceived threats from Argentina or incursion by Argentina into the Falkland Islands territorial waters could result in disruptions to our planned activities. This risk 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 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, including the DJ Basin and Marcellus Shale, require the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of natural gas.

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.

Our Marcellus Shale joint venture subjects us to certain financial, operational and legal obligations and additional risks associated with development activities in that region.

We have committed to make significant capital expenditures in the Marcellus Shale, including a Carried Cost Obligation of approximately $2.1 billion, and have agreed to other operational and legal obligations. If we do not meet our financial commitments or perform our other obligations on a timely basis, our rights to participate in the joint venture, and our anticipated operations in the Marcellus Shale, could be adversely affected.

We plan to drill numerous wells in the Marcellus Shale over a multi-year period. These activities will be subject to many risks including, among others:

- development drilling in emerging resource plays such as the Marcellus Shale may not result in commercially productive quantities of crude oil and natural gas reserves;
- we have less exploration and development experience in the Marcellus Shale than we have in other areas and limited information regarding ultimate recoverable reserves and production decline rates; therefore, our estimates of economically recoverable quantities of crude oil and natural gas reserves may vary substantially and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates;
- the high level of current and planned development activity in the Marcellus Shale may result in increased competition for drilling rigs and oilfield services such as hydraulic fracturing, gathering, processing and/or transportation, thus hindering our ability to develop our reserves and market our production;
- activism in New York, Pennsylvania and West Virginia against oil and gas development activities, particularly regarding the use of hydraulic fracturing, could, among other things, delay or limit our access to crude oil and natural gas reserves;
- additional environmental regulation or legislation could result in additional development and/or production costs;
- potential enactment of severance taxes or additional fees in Pennsylvania, such as the well impact fee enacted by the Pennsylvania legislature in 2012, would likely result in a lower rate of return on our development project; and
- our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could hinder our ability to develop our reserves or increase our development and operating costs; and
- development activity in the Marcellus Shale places additional burdens on our financial resources and internal financial controls.

We may not be able to compensate for or fully mitigate these risks. See Items 1. and 2. Business and Properties - Entry Into Marcellus Shale joint venture.

Indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2012, we had $4.1 billion of debt, of which $372 million is due within 12 months. Our indebtedness represented 33% of our total book capitalization (sum of debt plus shareholders' equity) at December 31, 2012.

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 revolving 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 12. Long-Term Debt.

Unavailability of capital resources at reasonable cost could have a negative impact on our liquidity and limit our growth.

The capital markets are currently less constrained than they were in the period subsequent to the global economic crisis of 2008. However, certain situations are increasing pressure on the capital markets and could cause funding sources to become constrained again. These situations include:

- the European debt crisis persists, with governments and banks requiring more economic assistance;
- fiscal situations are also worsening in OECD countries due to lingering effects of recession including slower growth rates;
- Basel III banking regulation impacts the amount and nature of capital required to be held by banks;
- quantitative easing programs generally weaken the currency of the country launching the stimulus, and discontinuance of such programs can result in spikes in interest rates;
- the risk of a potential negative stock market event, such as a sharp price decline or even a "crash", is intensified by lack of significant improvement in the US fiscal situation and fear that a combination of spending cuts and new taxes could push the country back into recession; and
- interest rates could rise if the US debt ceiling is not raised in a timely manner.

These situations have a negative impact on the availability and cost of capital. If we or our partners are unable to obtain financing, future development projects could be delayed or canceled, thus limiting our growth and future cash flows.

Failure to resolve long-term US fiscal issues, primarily the federal budget deficit and the debt ceiling, could have a negative impact on the economy, slowing growth and reducing demand for our products.

In the coming months, the US will face three critical deadlines: on March 1, mandatory across-the-board spending cuts (sequestration) are scheduled to take effect; by late March a new spending bill must be passed to fund the federal government, and in May, the debt ceiling suspension will expire.

Congress and the Administration are deeply divided over the issues and there is a lack of consensus on the extent and timing of an increase in the borrowing limit and whether deficit reductions should come from spending cuts, tax increases or a combination of both. In addition, the US government has failed to address increasing entitlement costs and fundamental tax reform. Failure to solve these long term fiscal challenges could undermine the economic recovery, reducing demand and slowing growth. For example:

- if the debt ceiling is not raised in a timely manner, the US could default on its debt and/or experience a reduction in its credit rating, and interest rates could increase;
- servicing the US debt diverts resources from investments that would spur economic growth;
- increased borrowing means that the US government competes with businesses for financing and businesses may be unable to secure funds for expansion;
- a federal deficit reduction program, if undertaken too rapidly, could put the economy back into recession; and
- austerity measures undertaken to reduce the US deficit could result in increased social unrest, such as is occurring in the European Union.

To the extent fiscal issues are not addressed, slower economic growth and a reduction in demand for our products could occur. Such developments could have a significant negative impact on our earnings, cash flows, access to capital, liquidity and financial position. In addition, economic uncertainty makes it more difficult for us to design our exploration and development strategy and related capital investment programs, which are typically formulated years in advance.

Our operations may be adversely affected by the European debt crisis.

During 2011, the long term structural deficits in numerous European nations coupled with the deterioration of the economic outlook led the weaker nations to a liquidity and solvency crisis. Eurozone leaders have made numerous attempts to solve this debt crisis, but to date a sustainable long term solution has not been implemented and much uncertainty remains. The crisis has had a negative impact on major European banks which historically were significant providers of credit to the energy sector, globally and in the US. In 2012, Cyprus requested a financial rescue in order to recapitalize Cypriot banks, which had been weakened by their exposure to the Greek economy.

Failure to successfully resolve the debt crisis could lead to significant losses for debt holders, including major European banks and investors, triggering additional capital requirements. In the worst case, the crisis could lead to the voluntary exit or expulsion of certain countries from the Euro currency block and/or a collapse of the eurozone financial system. A break up of the eurozone would be a deeply disruptive global economic event. The ongoing crisis continues to have a negative impact on the European economy. A prolonged downturn could disrupt the current US recovery and weaken global trade, hamper key emerging markets such as China and India, and result in another global recession with reduced demand and lower prices for the oil and gas we produce.

A eurozone debt crisis could have the following impacts, among others:

- disruption of the Euro currency system and/or changes in currency regimes;
- disruption of the payment and settlement system;
- severe inflation due to currency depreciation;
- loss of access to energy markets;
- sovereign and corporate defaults on euro-denominated debt;
- failures of banks or financial systems or reduced ability of banks to lend due to higher funding costs;
- devaluation of assets; and
- regional economic recession which could spread globally.

The economic developments mentioned above could have a significant negative impact on our earnings, cash flows, access to capital, liquidity and financial position.

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 years leading up to 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 fossil fuels. 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.

The adoption of GHG emission or other environmental legislation could result in additional operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.

In recent years, each house of Congress has considered legislation to address GHG emissions, such as the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill, passed by the House of Representatives, and The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, introduced to the Senate. Future legislation could include mandatory carbon dioxide emissions goals, measures to encourage use of renewable energy over fossil-based fuels, higher penalties and fines for violations of various environmental laws, or other regulations designed to curb GHG emissions.

One measure considered frequently has been the establishment of a “cap and trade” system for restricting GHG emissions in the US. Under such system, certain sources of GHG emissions would be required to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances would be expected to escalate significantly.

The EPA requires regulated facilities and oil and natural gas operators meeting a certain emissions threshold to report GHG emissions. Beyond measuring and reporting, the EPA has issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding GHG pollution threatens the public health and welfare of current and future generations and has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

Even if federal GHG legislation or regulation is not adopted, almost one-half of the states have taken action to reduce GHG emissions through the development of GHG emissions inventories and the establishment of regional GHG cap and trade programs. Most of the state-level initiatives have focused on large sources of GHG emissions. It is possible, however, that smaller sources could become subject to state regulation of GHGs.

During 2012, approximately 56% of our total crude oil production, 57% of our total natural gas production, and 100% of our NGL production from total consolidated volumes was derived in the US. Therefore, any laws or regulations that may be adopted to restrict or reduce emissions of US GHGs could require us to incur additional operating costs and increase our development cycle time. In addition, we could be required to make significant capital expenditures to comply with new environmental legislation, which would cause us to divert capital from exploration, development and production activities. GHG regulation may make our products less desirable than lower GHG emitting energy sources, such as wind and solar. It is possible, however, that GHG regulation may increase the competitiveness of our products with respect to higher GHG emitting energy sources, such as coal. At this time it is impossible to predict with certainty how a GHG regulation scheme would affect the oil and gas market.

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

We operate in the highly competitive areas of crude oil and natural gas exploration, exploitation, 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 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 2013. Exploratory drilling requires significant capital investment and does not always result in commercial quantities of hydrocarbons or new development projects. For example, we incurred dry hole expense in 2012 associated with the Deep Blue exploratory well in the deepwater Gulf of Mexico and the Trema exploratory well offshore Cameroon.

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 deepwater Gulf of Mexico or international projects, it may take several years to evaluate the future potential of an exploration 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, such as onshore US shale areas and offshore areas such as ultra-deepwater Gulf of Mexico, the Eastern Mediterranean or West Africa, 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, revenue 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, such as our Marcellus Shale acquisition in 2011 and our DJ Basin asset acquisition in 2010. 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 cannot provide assurance that we will be able to identify attractive acquisition opportunities. Even if we do identify attractive opportunities, we cannot provide assurance that we will 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, such as the sales of certain non-core onshore US and North Sea assets in 2012. 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 would 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 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.

We operate in the US and some other countries which have proven to be litigious environments. Most oil and gas companies, such as us, are involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. In addition, oil and gas companies are often the target of “legacy lawsuits”. A “legacy lawsuit” refers to a lawsuit by a landowner claiming that oil and gas operations, often performed many years ago and by another operator, caused pollution or contamination of a property. Claims against the current operator may be onerous while not allowing for cleanup at the site.

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, such as the horizontal Niobrara and Marcellus Shale drilling programs, Gunflint, Alen, and Tamar. 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 revolving bank 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 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 - 2013 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 or letters of credit, 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 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 almost $1.4 billion in cash and cash equivalents at December 31, 2012, 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 and interest 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 fluctuated significantly in 2012. 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.

We cannot assure that our hedging transactions will 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 10. 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 Hurricane Sandy in 2012, the 2011 earthquake and subsequent tsunami in Japan, and the 2010 Deepwater Horizon Incident. 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.

From time to time, in varying degrees, political developments and international, federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the crude oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect crude oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations 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, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make substantial expenditures to comply with governmental laws and regulations.

Our operations are subject to complex international, federal, state and local environmental laws and regulations including, for example, in the case of federal laws, 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 and regulations change frequently and the implementation of new, or the modification of existing, laws or regulations could negatively impact our operations. 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. In addition, we may incur costs and penalties in addressing regulatory agency procedures involving instances of possible non-compliance. See Items 1. and 2. Business and Properties - Regulations.

A change in US energy policy can 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 Corporate Average Fuel Economy (CAFE) standards enacted in 2012 will result in a rapid increase in the fuel economy of cars and light trucks and could potentially have both a negative impact on demand for crude oil and a positive impact on demand for natural gas for road transport use. GHG emissions regulations could 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 hindered 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 the DJ Basin, Marcellus Shale, deepwater Gulf of Mexico, and in some international locations that typically have limited availability of equipment and personnel, such as West Africa and the Eastern Mediterranean.

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. The recovery of global crude oil prices during 2011 has resulted in increased exploration and production activity, thus increasing 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

See Item 8. Financial Statements and Supplementary Data – Note 20. Commitments and Contingencies.

Item 4. Mine Safety Disclosures

Not Applicable.

Executive Officers

The following table sets forth certain information, as of February 7, 2013, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson [(1)]	62	Chairman of the Board, Chief Executive Officer and Director
David L. Stover [(2)]	55	President, Chief Operating Officer
Kenneth M. Fisher [(3)]	51	Senior Vice President, Chief Financial Officer
Ted D. Brown [(4)]	57	Senior Vice President, Northern Region
Rodney D. Cook [(5)]	55	Senior Vice President, International
Susan M. Cunningham [(6)]	57	Senior Vice President, Exploration
Arnold J. Johnson [(7)]	57	Senior Vice President, General Counsel and Secretary
Andrea Lee Robison [(8)]	54	Vice President, Human Resources and Administration

(1) Charles D. Davidson was elected Chief Executive Officer of Noble Energy in October 2000 and Chairman of the Board in April 2001, also serving as President until April 2009 (at which time Mr. Stover assumed that position). Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From September 1993 to March 1997, he served as a Senior Vice President of Vastar. From 1972 to October 1993, he held various positions with ARCO.

(2) David L. Stover was elected President and Chief Operating Officer of Noble Energy in April 2009. Prior thereto, he served as Executive Vice President and Chief Operating Officer of Noble Energy from August 2006 to April 2009. He served as Senior Vice President of North America and Business Development from July 2004 through July 2006, and he served as Noble Energy's Vice President of Business Development from December 2002 through June 2004. Previous to his employment with Noble Energy, he was employed by BP America, Inc. as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar, as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999. From 1979 to 1994, he held various positions with ARCO.

(3) Kenneth M. Fisher was elected Senior Vice President and Chief Financial Officer of Noble Energy in November 2009. Prior to joining Noble Energy, Mr. Fisher served as Executive Vice President of Finance for Upstream Americas for Shell from July 2009 to November 2009. Prior to his most recent position with Shell, Mr. Fisher served as Director of Strategy & Business Development for Royal Dutch Shell plc in The Hague from August 2007 to July 2009. He served as Executive Vice President of Strategy & Portfolio for Shell's downstream business in London from January 2005 to August 2007. Mr. Fisher joined Shell in August 2002 and served as Chief Financial Officer for Shell Oil Products U.S. until December 2004. As Chief Financial Officer for Shell Oil Products U.S., he was responsible for U.S. oil products finance, information technology and contracting and procurement activities. Prior to joining Shell, he held positions of increasing responsibility with General Electric Company (GE) from 1984 to 2002, including Vice President and Chief Financial Officer of the Aircraft Engines Services division and Director of Finance & Business Development of GE's Asia Pacific plastics business.

(4) Ted D. Brown was elected a Senior Vice President of Noble Energy in April 2008 and is currently responsible for the Northern Region of our North America division. He served as Vice President, responsible for the same region, from August 2006 to April 2008 and as a vice president of that division since joining Noble Energy upon our acquisition of Patina Oil & Gas Corporation (Patina) in May 2005. He served as Senior Vice President of Patina from July 2004 to May 2005. Prior thereto he served as Director, Piceance Basin Asset along with Engineering Manager for Williams and Barrett Resources since 1993 and, before that, in various positions with Union Pacific Resources and Amoco Production Company.

(5) Rodney D. Cook was elected a Senior Vice President of Noble Energy in April 2008 and is currently responsible for the International division. He served as Vice President of Noble Energy, responsible for the Southern Region of our North America division, from August 2006 to April 2008 and as a vice president of that division from May 2005 to August 2006. He served as Manager of our West Africa and Middle East Business Unit from 2002 to 2005. Prior thereto he served as Operations Manager of the International division since 1996. From 1980 to 1996 he held various positions with Noble Energy. Prior to joining Noble Energy in 1980, Mr. Cook held various positions with Texas Pacific Oil.

(6) Susan M. Cunningham was elected a Senior Vice President of Noble Energy in April 2001 and is currently responsible for our world-wide exploration. Prior to joining Noble Energy, Ms. Cunningham was Texaco’s Vice President of worldwide exploration from April 2000 to March 2001. From 1997 through 1999, she was employed by Statoil, beginning in 1997 as Exploration Manager for deepwater Gulf of Mexico, appointed a Vice President in 1998 and responsible, in 1999, for Statoil’s West Africa exploration efforts. She joined Amoco Canada in 1980 as a geologist and held various exploration and development positions with Amoco Production Company until 1997.

(7) Arnold J. Johnson was elected Senior Vice President, General Counsel and Secretary of Noble Energy in July 2008. Prior thereto, he served as Vice President, General Counsel and Secretary of Noble Energy since February 2004. He served as Associate General Counsel and Assistant Secretary of Noble Energy from January 2001 through January 2004. Previous to his employment with Noble Energy, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar from 1997 through 2000. From 1980 to March 1989, he held various positions with ARCO.

(8) Andrea Lee Robison was elected a Vice President of Noble Energy in November 2007 and is responsible for Human Resources and Administration. Prior thereto, she served as Director of Human Resources from May 2002 through October 2007. Prior to joining us, Ms. Robison was Manager of Human Resources for the Gulf of Mexico Shelf for BP America, Inc. from September 2000 through April 2002. Prior to her employment at BP, she served as HR Director at Vastar from 1997 through September 2000, and Compensation Consultant from January 1994 through 1996. From 1980 through 1993, she held various positions with ARCO.

PART II

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

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

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

	High	Low	Dividends Per Share
2011			
First Quarter	$ 98.99	$ 81.27	$ 0.18
Second Quarter	98.72	82.50	0.18
Third Quarter	101.27	69.25	0.22
Fourth Quarter	99.17	65.91	0.22
2012			
First Quarter	$ 105.46	$ 93.57	$ 0.22
Second Quarter	100.98	76.83	0.22
Third Quarter	97.60	82.33	0.22
Fourth Quarter	103.08	90.00	0.25

On January 28, 2013, the Board of Directors declared a quarterly cash dividend of $0.25 per common share, which will be paid February 25, 2013 to shareholders of record on February 11, 2013.

Transfer Agent and Registrar The transfer agent and registrar for our common stock is Wells Fargo Bank, N.A., 161 North Concord Exchange, South St. Paul, MN, 55075.

Stockholders' Profile Pursuant to the records of the transfer agent, as of January 18, 2013, the number of holders of record of our common stock was 635.

Stock Repurchases The following table summarizes repurchases of our common stock occurring fourth quarter 2012.

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)
10/1/2012 - 10/31/12	839	$ 94.47	—	—
11/1/2012 - 11/30/12	6,726	92.48	—	—
12/1/2012 - 12/31/12	601	99.77	—	—
Total	8,166	$ 93.22	—	—

(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under 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, 2012.

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	6,205,786	$ 70.27	7,486,668
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	6,205,786	$ 70.27	7,486,668

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2007 to December 31, 2012. 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.

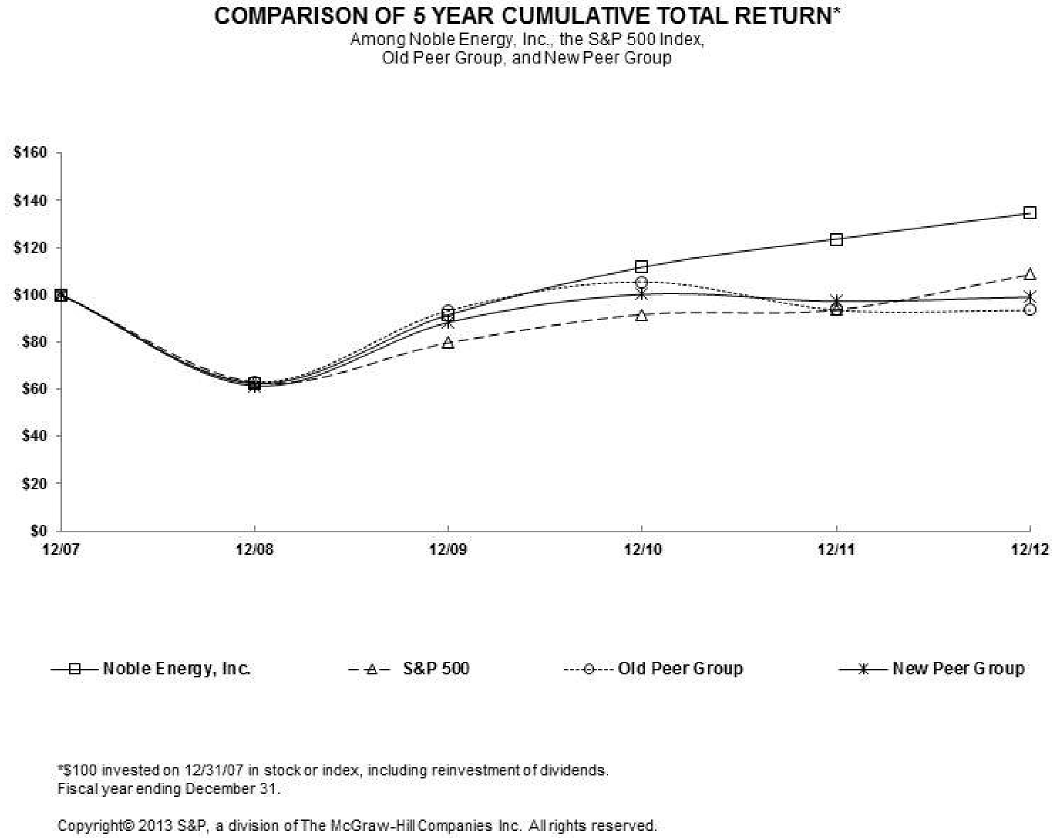
The companies in the old peer group consisted of the following:

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

On January 23, 2012, the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) made changes to our compensation peer group to remove Forest Oil Corp. and Talisman Energy Inc. from the old peer group listed above given their growing dissimilarity to our operational and financial characteristics, and add Marathon Oil Corporation and Continental Resources, Inc., which are US companies listed on the NYSE with a balance of projects similar in size and scope to ours. After the change in companies, the 2012 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.
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

The comparison assumes $100 was invested on December 31, 2007 in our common stock, in the S&P 500 Index and in our peer group of companies and assumes that all of the dividends were reinvested



Year Ended December 31,	2007	2008	2009	2010	2011	2012
Noble Energy, Inc.	$ 100.00	$ 62.51	$ 91.55	$ 111.73	$ 123.62	$ 134.52
S&P 500	100.00	63.00	79.67	91.67	93.61	108.59
Old Peer Group	100.00	62.91	93.30	105.49	93.57	93.54
New Peer Group	100.00	61.52	88.30	100.19	97.29	99.08

Item 6. Selected Financial Data

	Year Ended December 31,				
	2012	2011	2010	2009	2008
(millions, except as noted)					
Revenues and Income (Loss)					
Total Revenues	$ 4,223	$ 3,404	$ 2,713	$ 2,160	$ 3,491
Income (Loss) from Continuing Operations	965	412	631	(159)	1,204
Net Income (Loss)	1,027	453	725	(131)	1,350
Per Share Data					
Earnings (Loss) Per Share - Basic					
Income (Loss) from Continuing Operations	$ 5.43	$ 2.34	$ 3.61	$ (0.92)	$ 6.98
Net Income (Loss)	5.77	2.57	4.15	(0.75)	7.83
Earnings (Loss) Per Share - Diluted					
Income (Loss) from Continuing Operations	5.37	2.31	3.56	(0.92)	6.75
Net Income (Loss)	5.71	2.54	4.10	(0.75)	7.58
Cash Dividends Per Share	0.91	0.80	0.72	0.72	0.66
Year-End Stock Price Per Share	101.74	94.39	86.08	71.22	49.22
Weighted Average Shares Outstanding					
Basic	178	176	175	173	173
Diluted	180	179	177	173	176
Cash Flows					
Net Cash Provided by Operating Activities	$ 2,933	$ 2,170	$ 1,946	$ 1,508	$ 2,285
Additions to Property, Plant and Equipment	3,650	2,594	1,885	1,268	1,971
Acquisitions	—	527	458	—	292
Proceeds from Divestitures	1,160	77	564	3	131
Financial Position					
Cash and Cash Equivalents	$ 1,387	$ 1,455	$ 1,081	$ 1,014	$ 1,140
Commodity Derivative Instruments - Current	63	10	62	13	437
Property, Plant, and Equipment, Net	13,551	12,782	10,264	8,916	9,004
Goodwill	635	696	696	758	759
Total Assets	17,554	16,444	13,282	11,807	12,384
Long-term Obligations					
Long-Term Debt	3,736	4,100	2,272	2,037	2,241
Deferred Income Taxes	2,218	2,059	2,110	2,076	2,174
Commodity Derivative Instruments	3	7	51	17	2
Asset Retirement Obligations	333	344	208	181	184
Other	474	401	371	349	300
Shareholders' Equity	8,258	7,265	6,848	6,157	6,309
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	86	56	54	55	59
Average Realized Price ($/Bbl) [(1)]	$ 101.52	$ 99.17	$ 75.76	$ 55.32	$ 79.38
Consolidated Natural Gas Sales (MMcf/d)	774	806	781	776	762
Average Realized Price ($/Mcf) [(1)]	$ 2.19	$ 3.00	$ 2.98	$ 2.52	$ 5.00
Consolidated NGL Sales (MBbl/d)	16	15	14	10	9
Average Realized Price ($/Bbl)	$ 35.36	$ 48.35	$ 41.21	$ 27.96	$ 50.15
Proved Reserves					
Crude Oil, Condensate and NGL Reserves (MMBbls)	357	369	365	336	311
Natural Gas Reserves (Bcf)	4,964	5,043	4,361	2,904	3,315
Total Reserves (MMBoe)	1,184	1,209	1,092	820	864
Number of Employees	2,190	1,876	1,772	1,630	1,571

(1) Prices through 2010 include effects of oil and gas hedging activities. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and 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. 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, growing portfolio of assets that is balanced between US and international projects, while maintaining a strong balance sheet and ample liquidity levels. We primarily focus on organic growth from exploration and development drilling and augment that with a periodic, opportunistic new business development (mergers and acquisition) capability. We manage the portfolio for superior returns and to ensure geographic portfolio diversification, with periodic divestments of non-core assets. We focus on basins or plays where we have strategic competitive advantage and which we believe generate superior returns.

Core operating areas are the onshore US (DJ Basin and Marcellus Shale), deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean. As a result of our continued exploration success, we are focused on the execution of a significant portfolio of major development projects that will deliver visible growth including, among others: the horizontal Niobrara in the DJ Basin and the Marcellus Shale, onshore US; Gunflint and Big Bend in the deepwater Gulf of Mexico; Tamar and Leviathan, offshore Israel; offshore Cyprus; Alen, Carla, and Diega, offshore West Africa.

Our major development projects typically offer long life, sustained cash flows after investment and attractive financial returns. We maintain a diversified portfolio between US and international assets and strive to maintain a balanced geographic and political risk profile. We also maintain a geographical diversity of production mix among crude oil, US natural gas, and international natural gas.

Current Business and Industry Environment The global economy continued its recovery during 2012. Although there was modest growth in the US, China and emerging markets, Europe continued to struggle with its debt crisis. In the US, uncertainty continues to surround resolution of federal deficit issues. It is difficult to predict the economic consequences on global markets as governments attempt to resolve these issues.

In the global crude oil market, supplies grew, primarily due to the application of horizontal drilling technology to liquids plays and increasing supplies from unconventional sources (oil from tight formations and oil sands) in the US and Canada. Prices remained strong, supported by modest demand growth and continued security and other threats to the global crude oil supply system. Brent prices remain at a premium to WTI primarily due to transportation constraints in the US Mid-Continent area which impact WTI netbacks.

In the US, the application of horizontal drilling technology has significantly changed the natural gas markets, resulting in an oversupply of natural gas and considerably lower Henry Hub spot and forward prices. Increased drilling in liquids-rich gas areas and increased associated gas production from oil plays has yielded significant growth in onshore US NGL production. As a result, the NGL market softened during 2012, and NGL prices declined.

Despite the uncertainty surrounding the global economy and continued volatility in commodity prices, we believe our portfolio positions us well moving forward. We have material new production onshore US and offshore Equatorial Guinea, substantial liquidity and cash flow, a solid balance sheet, and a line-up of major development projects which we expect to contribute to future growth.

2012 Results Noble Energy delivered significant growth in 2012. Expansion of our horizontal Niobrara and Marcellus Shale developments resulted in a 24% increase in Wattenberg production and a four fold increase in Marcellus Shale production. We realized further production increases from major new developments at Aseng, offshore Equatorial Guinea, and Galapagos, deepwater Gulf of Mexico, that came on line in 2011 and 2012, respectively. We moved forward on our major development projects, each of which will yield significant new production in future years, discovered new resources at Big Bend in the deepwater Gulf of Mexico and Carla, offshore Equatorial Guinea, and farmed into new opportunities offshore the Falkland Islands and Sierra Leone. Finally, we enhanced our portfolio with selective divestitures of non-core, onshore US and North Sea properties, and maintained our strong balance sheet.

Our 2012 financial results included:

- net income over $1.0 billion (including $965 million from continuing operations) as compared with $453 million (including $412 million from continuing operations) for 2011 ;
- dry hole cost of $155 million, as compared with $105 million for 2011;
- gain on divestitures of $154 million as compared with $25 million for 2011;
- asset impairment charges of $104 million as compared with $757 million for 2011;
- gain on commodity derivative instruments of $75 million (including unrealized mark-to-market gain of $109 million) as compared with $42 million gain on commodity derivative instruments (including unrealized mark-to-market loss of $22 million) for 2011;
- diluted earnings per share of $5.71, as compared with $2.54 for 2011;
- cash flows provided by operating activities of $2.9 billion, as compared with $2.2 billion in 2011;
- received $1.2 billion in proceeds from divestments of non-core assets, as compared with $77 million in 2011;
- capital spending on a cash basis of $3.7 billion as compared with $3.1 billion in 2011 (including $527 million for the Marcellus Shale asset acquisition);
- exercised option to increase credit facility from $3.0 billion to $4.0 billion, enhancing our liquidity position;
- ending cash and cash equivalents balance of $1.4 billion at December 31, 2012, as compared with $1.5 billion at December 31, 2011;
- total liquidity of $5.4 billion at December 31, 2012, consisting of year-end cash balance plus funds available under our credit facility, as compared with $4.5 billion at December 31, 2011; and
- year-end ratio of debt-to-book capital of 33%, as compared with 38% at December 31, 2011.

Significant operational highlights for 2012 included the following:

Overall

- total sales volumes from continuing operations of 239 MBoe/d, a 12% increase as compared with 2011;
- liquids represent 46% of total sales volumes from continuing operations as compared to 37% in 2011; and
- year-end proved reserves of 1.2 BBoe, a decrease of 2% from year-end 2011.

Onshore United States

- increased DJ Basin (Wattenberg) total sales volumes to 77 MBoe/d, net, with horizontal production contributing 28 MBoe/d, net;
- spud 200 and completed 193 horizontal wells in the DJ Basin;
- expanded the Northern Colorado acreage position by 26,000 net acres to 230,000 net acres, where recent horizontal Niobrara results indicate recoveries comparable to Wattenberg;
- Marcellus Shale production grew to 92 MMcfe/d, net, as compared with 19 MMcfe/d, net, in 2011;
- drilled to total depth 89 and completed 71 gross horizontal wells in the Marcellus Shale and initiated production from the wet gas area;
- experienced higher recovery rates than anticipated in the DJ Basin and Marcellus Shale;
- entered new exploration area in Northeast Nevada; and
- completed non-core onshore asset dispositions.

Deepwater Gulf of Mexico

- announced a discovery at the Big Bend prospect;
- Galapagos produced at an average rate of 6 MBbl/d of crude oil, net; and
- acquired six deepwater Gulf of Mexico blocks at the Outer-Continental Shelf Sale 222.

International

- discovery of a new crude oil reservoir at Carla, offshore Equatorial Guinea;
- Aseng field, offshore Equatorial Guinea, produced at an average gross rate of 62 MBbl/d of crude oil (21 MBbl/d, net);
- acceleration of Alen development, offshore Equatorial Guinea;
- installed the Tamar platform and initiated the commissioning process;
- announced a strategic development partner for the Leviathan project, offshore Israel;
- announced the Tanin natural gas discovery, offshore Israel;
- entered into new positions offshore Falkland Islands and Sierra Leone;
- secured contract with new-build drillship capable of reaching deep oil targets in the Eastern Mediterranean; and
- completed the sale of our Dumbarton and Lochranza assets in the North Sea.

Acquisitions and Divestitures

Strategic Partner for Leviathan The Leviathan field, offshore Israel, is the largest conventional natural gas discovery in our history, with resources available for both domestic and export markets. During 2012, we and our existing partners in the Leviathan project commenced a process to identify a partner who could provide technical and financial support as well as midstream and downstream expertise. On December 2, 2012, we and our existing partners announced that we had agreed in principle on a proposal to sell a 30% working interest in the Leviathan licenses to Woodside Energy Ltd. (Woodside). Woodside is Australia's largest producer of LNG with over 25 years of experience and has strong working relationships with many potential customers in the Asian LNG markets. We expect to execute a final agreement with Woodside during the first half of 2013.

2012 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. Further, proceeds from divestitures provide additional flexibility in the implementation of our international exploration and development programs and the acceleration of horizontal drilling activities in the DJ Basin and Marcellus Shale. During 2012, divestitures generated net proceeds of approximately $1.2 billion.

On August 13, 2012, we closed the sale of our 30% non-operated working interest in the Dumbarton and Lochranza fields, located in the UK sector of 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. We reversed a deferred tax liability and recognized a corresponding income tax benefit of $99 million related to the sale. Net daily production was approximately 5 MBoe/d at the time of the sale.

During third quarter 2012, we closed on three sales of onshore US properties in Kansas, western Oklahoma, western Texas, and the Texas Panhandle for total proceeds of $1.0 billion. The properties included our interests in about 1,400 producing wells on approximately 109,000 net acres. As of the effective date, April 1, 2012, net daily production was approximately 12.5 MBoe/d.

Additionally, we are continuing the process of marketing certain non-core onshore US properties and are currently soliciting bids. As of December 31, 2012, the Board of Directors and management had not committed to any specific plans to sell the assets, individually or as packaged groups. Therefore, none of these assets was reclassified as held-for-sale at December 31, 2012.

2012 Entry into Falkland Islands Joint Venture In August 2012, we entered into an agreement with Falkland Oil and Gas Limited (FOGL) and subsequently acquired an interest in FOGL's extensive license areas consisting of approximately 10 million undeveloped acres, gross, located south and east of the Falkland Islands.

2012 Entry into Sierra Leone In September 2012, the Government of Sierra Leone awarded us participation in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million acres, gross. Under the terms of the award, Chevron (SL) Ltd. will be the operator and we will have a non-operated 30% working interest.

2012 Exit from Senegal/Guinea-Bissau We decided not to participate in additional appraisal activities and relinquished our acreage.

2011 Entry into Marcellus Shale Joint Venture On September 30, 2011, we entered an agreement with CONSOL to jointly develop oil and gas assets in the Marcellus Shale areas of southwest Pennsylvania and northwest West Virginia. The Marcellus Shale joint venture strengthened and rebalanced our portfolio, providing a new, material growth area, which has contributed to reserves and production growth and provides balance to our rapidly expanding international programs.

2011 Ecuador Exit In May 2011, we transferred our assets in Ecuador to the Ecuadorian government, receiving cash proceeds of $73 million. The net book value of the assets had been reduced due to previous impairment charges, resulting in a pre-tax gain of $25 million.

2010 DJ Basin Asset Acquisition In March 2010, we acquired substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for a total purchase price of $498 million. The acquisition added approximately 46 MMBoe of proved reserves at closing date, and approximately 10 MBoe/d to our daily production base, starting from the closing date. Included in the purchase were 323,000 total net acres, nearly 183,000 of which are located in the DJ Basin.

2010 Onshore US Sale In August 2010, we closed the sale of non-core assets in the Mid-Continent and Illinois Basin areas for cash proceeds of $552 million and recorded a gain of $110 million. The sale included approximately 32 MMBoe of proved reserves, at closing date, and approximately 5.7 MBoe/d of production.

See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

Sales Volumes

On a BOE basis, total sales volumes from continuing operations were 12% higher in 2012 as compared with 2011, and our mix of sales volumes in 2012 was 46% global liquids, 23% international natural gas, and 31% US natural gas. Onshore US sales volumes increased due to continued acceleration of our horizontal drilling programs in Wattenberg and the Marcellus Shale program, which began at the end of the third quarter of 2011. In the deepwater Gulf of Mexico, new production from Galapagos and South Raton contributed to the increase in sales volumes. International crude oil sales volumes were higher in Equatorial Guinea due to the commencement of crude oil production at Aseng in the fourth quarter of 2011. Israel natural gas sales volumes were lower as we have reduced the rate of production from the Mari-B field in order to manage the reservoir. See Results of Operations – Revenues below.

Commodity Price Changes and Hedging

Historically, crude oil, natural gas and NGL prices have exhibited significant volatility. The crude oil market remained relatively robust during 2012, benefiting from continued threats to the global crude oil supply system. Total consolidated average realized crude oil prices for 2012 increased 2% as compared with 2011.

The domestic natural gas market remains weak, primarily due to an abundant supply and higher levels of gas in storage. US average realized natural gas prices for 2012 decreased 33% as compared with 2011.

Prices continue to be impacted by the slowdown in the global economic recovery, influenced by uncertainty over the eurozone debt crisis, and an increase in supply. As long as development activity continues at, or near, the current level and there is no significant increase in demand, downward pressure on commodity prices is likely to continue. See Item 6. Selected Financial Data for average realized prices for 2008 - 2012. See also Operating Outlook - Potential for Future Asset Impairments, below.

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 2013. 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 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 related to production in future periods. Unrealized mark-to-market gains or losses recognized in the current period will be realized in the future when they are cash settled in the month that the related production occurs. 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 10. Derivative Instruments and Hedging Activities.

Asset Impairment Charges During 2012, we recorded impairment charges of $104 million, related to our South Raton and Piceance developments due to near-term declines in crude oil and natural gas prices, respectively, and our Mari-B, Pinnacles and Noa fields, offshore Israel, due to end-of-field life declines in production. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

OPERATING OUTLOOK

2013 Outlook We continue to monitor the outlook for the global economy and numerous critical factors including the US federal budget deficit and long-term fiscal situation, the European debt crisis and their potential impacts on global economic growth and commodity prices. We expect the overall global economy to continue a pattern of modest growth, while the European economy is likely to continue to struggle with low growth resulting from its debt crisis.

We expect global crude oil production volumes to continue to grow, primarily due to increases in the US and Canada from continued application of horizontal drilling technology. This growth will likely result in an increase in OPEC spare production capacity. Meanwhile, political risk remains strong: North African and Mideast conflicts, civil unrest, and other potential supply interruption risks are likely to continue. Global crude oil demand is expected to grow in 2013 as the global economy continues to grow. Global crude oil prices will be determined by these supply and demand factors. In the US, de-bottlenecking in the Mid-Continent as transportation improves will also increase Gulf Coast supply; as a result, we expect that US prices will continue to trade at a discount to Brent.

In the US, we expect natural gas prices to be range-bound, as production has continued to increase, even with lower rig counts, until new demand sources catch up with supply growth. One significant issue potentially impacting the industry is the amount of US natural gas exports via LNG that will be approved by the DOE.

Because the global economic outlook and commodity price environment are uncertain, we have built a strong liquidity position to ensure financial flexibility and planned a flexible capital spending program which will support both major project development and exploration activities in a volatile commodity price environment. See 2013 Capital Investment Program below.

2013 Production Our expected crude oil, natural gas and NGL production for 2013 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;
- timing of major development project completion and initial production, including Tamar, offshore Israel, and Alen, offshore Equatorial Guinea, which are scheduled to begin producing in 2013;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- pace of increase of development activity in both wet gas and dry gas areas of the Marcellus Shale;
- divestments of non-core operating assets;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations, and the Mari-B field in Israel (See Items 1. and 2. Business and Properties - Delivery Commitments);
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth, production rates from the Mari-B, Noa and Pinnacles wells, and anticipated production from Tamar, offshore Israel;
- variations in West Africa sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Rocky Mountain and/or Marcellus Shale areas of our US operations;
- third party facilities reliability in the Wattenberg and/or Rocky Mountain areas of our US properties which may cause restrictions or interruptions in mid-stream processing facilities;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain and/or Marcellus Shale areas of our US operations;
- potential drilling and/or hydraulic fracturing permit delays due to future regulatory changes;
- potential purchases of producing properties; and
- potential shut-in of US producing properties if storage capacity becomes unavailable.

2013 Capital Investment Program Our total capital investment program for 2013 is estimated at $3.9 billion. The capital investment program allocates approximately 60% to onshore US, 6% for deepwater Gulf of Mexico, 10% to the Eastern Mediterranean, 15% to West Africa and 9% to corporate and other. Exploration and appraisal activity within these geographic areas is expected to receive 15% of total capital.

The 2013 capital investment program will exceed operating cash flows and is expected to be funded from cash flows from operations, cash on hand, and borrowings under our revolving 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. 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 new international locations. During 2012, we expanded our global presence by entering into joint ventures in two new areas, offshore Falkland Islands and offshore Sierra Leone, and by acquiring acreage in Northeast Nevada. Additionally, we drilled a successful exploratory well at Big Bend in the deepwater Gulf of Mexico and drilled our first exploratory well at Scotia, offshore Falkland Islands.

In furtherance of our commitment to global offshore exploration and development, on September 27, 2012, we announced that we have entered into a 36-month drilling services contract for a new-build drillship, the Atwood *Advantage*. See Items 1. and 2. Business and Properties - International, above.

We continually evaluate and high-grade 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 15% of our $3.9 billion capital investment program in 2013 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.

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. As a result, in a future period, dry hole cost could be material. See Results of Operations - Oil and Gas Exploration Expense, below. See also Item 1A. Risk Factors - *Our entry into new exploration ventures in areas in which we have no prior experience subjects us to additional risks*.

Major Development Project Inventory Our current inventory of major development projects includes the horizontal Niobrara, Marcellus Shale, Tamar, Alen, Diega and Carla, Gunflint, Big Bend, Leviathan, Cyprus and other West Africa gas projects. These projects will require significant capital investments.

As noted above, we expect to spend substantial amounts on our major development projects in 2013. We plan to fund these projects from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing.

The second of our major development projects brought online since 2011, Galapagos, located in the deepwater Gulf of Mexico, began commercial crude oil production in June 2012 and two additional major development projects, Tamar, offshore Israel, and Alen, offshore Equatorial Guinea, are on schedule to begin commercial production in 2013. The additional production from these three major development projects, along with Aseng, offshore Equatorial Guinea, which began production in 2011, is expected to begin generating significant cash flow which will be available to meet a substantial portion of future 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 – *Failure to effectively execute our major development projects could result in significant delays and/or cost over-runs, damage to our reputation, limitations on our growth and negative effects on our operating results, liquidity and financial position, 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,* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments.*

Potential for Future Asset Impairments We recorded asset impairment charges of $104 million during 2012. A further decline in future NYMEX 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 oil and 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.

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 $116 million at December 31, 2012.

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

Climate Change Climate change has become the subject of an important public policy debate. While climate change remains a complex issue, scientific research suggests that an increase in greenhouse gas emissions (GHGs) may pose a risk to society and the environment. In 2011, the United Nations-sponsored Intergovernmental Panel on Climate Change, a scientific body which provides an assessment of the risk of climate change, issued its Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation, in which it concluded that it is likely that climate change is fueling extreme weather and predicted that there will be an escalation of impacts on people and economies.

In November 2012, the World Bank issued a report based on recent scientific literature and new analysis of likely impacts and risks that would be associated with a 4^{o}C warming within this century. Risks include rise in sea-levels, increases in tropical cyclone intensity, increasing aridity and drought. The report predicted severe impacts on coastal cities, food and water systems, ecosystems, and human health and called for international cooperation to prevent global warming. Also in 2012, a coalition of institutional investors said that rapidly growing greenhouse gas and more extreme weather were increasing investment risks globally and called on governments to increase action on climate change and boost investment in clean energy technology.

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 fossil fuels 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 fossil fuels 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.

Climate change legislation and regulations have been adopted by many foreign countries and states in the US; however, legislation and regulations have not been enacted in all of the foreign countries where we operate or at the federal level in the US. Due to the current global economic environment and debt crisis, many countries are facing pressure to reduce spending or implement austerity measures. This could result in the diverting of attention away from the environmental agenda as well as limited financial resources available for spending on environmental policies. The status of development of many state and federal climate change regulatory initiatives in areas where we operate makes it difficult to predict with certainty the future impact on us, including accurately estimating the related compliance costs that we may incur.

The EPA issued regulations requiring monitoring and reporting of GHG emissions from petroleum and natural gas systems. This action does not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits. These and other US, and other international, regulations may affect our operations by potentially increasing operating costs for maintaining our facilities, compliance costs for managing new GHG regulatory programs and capital costs for installing new GHG emission controls.

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.

In December 2012, the annual conference of parties reconvened in Doha, Qatar, to continue pursuing the global accord, committing countries to cut GHG emissions. The parties 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. See Items 1. and 2. Business and Properties – Regulations and the following risk factors listed in Item 1A. Risk Factors –

- *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs;* and
- *The adoption of GHG emission or other environmental legislation could result in additional operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce*.

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, approximately 54% of our 2012 total sales volumes from continuing operations were natural gas. GHG emissions regulation could reduce the demand for the crude oil we produce. At the same time, the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as crude oil and coal. Therefore, the use of natural gas may increase should the use of other fossil fuels decrease due to GHG emissions regulation.

The 2011 incident at the Fukushima nuclear plant in Japan has re-opened debate about the future of nuclear power as an alternative to fossil fuels, and public concern about nuclear safety has been heightened. In response, Germany, Japan, and other nations have announced future shutdowns of nuclear plants and/or moratoria on future nuclear plant construction, resulting in increased demand for alternate fuel sources, including natural gas, for power generation.

Furthermore, 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, as the EPA's new GHG standards for light duty vehicles became effective in 2011, natural gas may prove to be a more attractive transportation fuel. This may increase the market demand for natural gas.

Physical Impacts of Climate Change on our Costs and Operations There has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Extreme weather conditions limit our production and increase our costs, and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations, particularly our offshore operations and our onshore US operations in the DJ Basin and Marcellus Shale. See Item 1A. Risk Factors – *The insurance we carry is insufficient to cover all of the risks we face, which could result in significant financial exposure*.

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

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,		
	2012	2011	2010
(millions, except per share)			
Total Revenues	$ 4,223	$ 3,404	$ 2,713
Total Operating Expenses	2,811	2,870	1,944
Operating Income	1,412	534	769
Total Other (Income) Expense	56	32	(79)
Income from Continuing Operations Before Income Taxes	1,356	502	848
Income from Continuing Operations	965	412	631
Discontinued Operations, Net of Tax	62	41	94
Net Income	1,027	453	725
Earnings from Continuing Operations Per Share			
Basic	5.43	2.34	3.61
Diluted	5.37	2.31	3.56

Factors contributing to the increase in income from continuing operations before income taxes in 2012 as compared with 2011 included the following:

- $819 million increase in total revenues due to higher sales volumes and higher average realized crude oil prices;
- $129 million increase in gain on divestitures;
- $33 million increase in gain on commodity derivative instruments; and
- $653 million decrease in asset impairment charges;

offset by:

- $115 million increase in total production expense;
- $132 million increase in exploration expense;
- $492 million increase in DD&A expense; and
- $45 million increase in general and administrative expense.

Factors contributing to the decrease in income from continuing operations before income taxes in 2011 as compared with 2010 included the following:

- $43 million increase in total production expense;
- $35 million increase in exploration expense;
- $59 million increase in DD&A expense;
- $66 million increase in general and administrative expense;
- $88 million decrease in net gain on asset sales;
- $613 million increase in asset impairment charges; and
- $115 million decrease in gain on commodity derivative instruments;

offset by:

- $691 million increase in total revenues due primarily to higher commodity prices and higher sales volumes.

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)				
2010 Sales Revenues	$ 1,499	$ 821	$ 203	$ 2,523
Changes due to				
Increase in Sales Volumes	55	55	21	131
Increase in Sales Prices	461	6	38	505
Change in Amounts Reclassified from AOCL	19	1	—	20
2011 Sales Revenues	2,034	883	262	3,179
Changes due to				
Increase (Decease) 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 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, 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
Year Ended December 31, 2010							
United States	39	400	14	119	$ 75.03	$ 4.17	$ 41.21
Equatorial Guinea (1)	11	226	—	49	78.44	0.27	—
Israel	—	130	—	22	—	4.03	—
Ecuador (3)	—	25	—	4	—	—	—
China	4	—	—	4	75.15	—	—
Total Consolidated Operations	54	781	14	198	75.76	2.98	41.21
Equity Investees (2)	2	—	5	7	77.98	—	53.68
Total Continuing Operations	56	781	19	205	$ 75.83	$ 2.98	$ 44.90

(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.

(3) Includes sales volumes through November 24, 2010. Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales were eliminated for accounting purposes. Electricity sales are included in other revenues. See Item 8. Financial Statements and Supplementary Data - Note 3. Acquisitions and Divestitures.

If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)					
	Year Ended December 31,					
	2012		2011		2010	
	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas
	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)
United States	$ (0.48)	$ 0.30	$ (3.22)	$ 0.77	$ (0.65)	$ 0.76
Equatorial Guinea	(6.17)	—	—	—	(3.41)	—
Total Consolidated Operations	(2.62)	0.17	(2.16)	0.37	(1.18)	0.40
Total Continuing Operations	(2.57)	0.17	(2.10)	0.37	(1.15)	0.40

Crude Oil and Condensate Sales 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 in the Wattenberg area;
- commencement of production at Galapagos and South Raton in the deepwater Gulf of Mexico which increased production by approximately seven 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 seven 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.

Revenues from crude oil and condensate sales increased by $535 million, or 36%, in 2011 as compared with 2010 due to the following:

- a 31% increase in total consolidated average realized prices due to increased demand resulting from the global economic recovery;
- higher sales volumes in the DJ Basin, including a 21% increase in Wattenberg sales volumes, attributable to the continued acceleration of our horizontal Niobrara development project; and
- higher sales volumes in Equatorial Guinea due to a higher number of liftings from our Alba field and due to the commencement of oil production at Aseng which impacted our sales volumes by approximately 9 MBbl/d in the fourth quarter;

partially offset by

- a decrease in onshore US volumes due to the divestment of non-core oil assets; and
- a decrease in deepwater Gulf of Mexico volumes due to natural field decline and third party downstream facility constraints.

Revenues from crude oil and condensate sales included deferred losses of $19 million in 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to crude oil revenues. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Natural Gas Sales 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 Wattenberg and Rocky Mountain areas 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 Wattenberg area; 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.

Revenues from natural gas sales increased by $62 million, or 8%, in 2011 as compared with 2010 due to the following:

- higher natural gas prices in Israel which benefit from strong global liquids markets;
- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by higher electricity production and lower levels of competitor natural gas imports from Egypt;
- higher sales volumes in the DJ Basin, including a 10% increase in Wattenberg sales volumes, attributable to the continued acceleration of our vertical and horizontal Niobrara drilling programs in the Wattenberg area;
- sales volumes from Marcellus Shale producing properties which we acquired September 30, 2011 and which added 19 MMcf/d to our 2011 sales volumes; and
- higher sales volumes in Equatorial Guinea as compared with 2010, during which time the Alba field experienced a planned shut-down for facilities maintenance and repair;

partially offset by

- a decrease in US realized natural gas prices which declined during 2011 primarily due to oversupply;
- a decrease in onshore US sales volumes due to the sale of certain non-core Oklahoma and Illinois Basin assets in 2010; and
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas.

Revenues from natural gas included a deferred loss of $1 million in 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to natural gas revenues. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

NGL Sales Most of our US NGL production is from the Wattenberg area. 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 to 2011 primarily due to higher supplies of NGLs resulting from increased wet gas drilling activities.

NGL sales revenues increased $59 million, or 29%, during 2011 as compared with 2010 due to higher realized prices and a slight increase in sales volumes due to ongoing development in the DJ Basin.

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,		
	2012	2011	2010
Net Income (in millions)			
AMPCO and Affiliates	$ 64	$ 68	$ 29
Alba Plant	122	125	89
Dividends (in millions)			
AMPCO and Affiliates	70	86	44
Alba Plant	130	139	95
Sales Volumes			
Methanol (MMgal)	156	155	129
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	5	5
Average Realized Prices			
Methanol (per gallon)	$ 1.07	$ 1.05	$ 0.84
Condensate (per Bbl)	104.56	108.76	77.98
LPG (per Bbl)	69.14	72.71	53.68

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

Net income from AMPCO and affiliates increased in 2011 as compared with 2010 due to increases in average realized methanol prices due to global economic recovery, and increases in methanol sales volumes as compared with 2010 when the plant experienced down time related to a major turnaround.

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

Net income from Alba Plant increased in 2011 as compared with 2010 due to increases in average realized condensate and LPG prices due to global economic recovery.

CONE Gathering LLC Under the terms of the gathering and marketing agreement that we entered into with CONE, we will pay CONE a minimum annual revenue commitment (MARC). The fee will be adjusted annually based on projected gathering volumes, operating expenses, capital expenditures, and other factors. Our share of CONE earnings were de minimis for the year ended December 31, 2012 and 2011. During 2012, we contributed $41 million to CONE. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Other Revenues Other revenues were as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Other Revenues	$ —	$ 32	$ 72

Other revenues include electricity sales from the Machala power plant, located in Machala, Ecuador, (through May 2011) and other revenue items. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

Operating Costs and Expenses

Operating costs and expenses were as follows:

	2012	Inc(Dec) from Prior Year	2011	Inc(Dec) from Prior Year	2010
(millions)					
Production Expense	$ 673	21 %	$ 558	8 %	515
Exploration Expense	409	48 %	277	14 %	242
Depreciation, Depletion and Amortization	1,370	56 %	878	7 %	819
General and Administrative	384	13 %	339	24 %	273
Gain on Divestitures	(154)	516 %	(25)	(78)%	(113)
Asset Impairments	104	(86)%	757	426 %	144
Other Operating (Income) Expense, Net	25	(71)%	86	34 %	64
Total	$ 2,811	(2)%	$ 2,870	48 %	1,944

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

	Total per BOE [1]	Total	United States	Equatorial Guinea	Israel	Other Int'l, Corporate [2]
(millions, except unit rate)						
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
Year Ended December 31, 2010						
Lease Operating Expense [3]	$ 4.39	$ 329	$ 258	$ 43	$ 9	$ 19
Production and Ad Valorem Taxes	1.67	125	103	—	—	22
Transportation and Gathering Expense	0.83	61	59	—	—	2
Total Production Expense	$ 6.89	$ 515	$ 420	$ 43	$ 9	$ 43
Total Production Expense per BOE		$ 6.89	$ 9.69	$ 2.38	$ 1.15	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 international 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 was $431 million in 2012 as compared with $346 million 2011, a 25% increase. Changes included the following:

- higher sales volumes from the Wattenberg area 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.

Lease operating expense increased in 2011 as compared to 2010 due to the following:

- higher US sales volumes from the DJ Basin due to ongoing development activities;
- higher sales volumes in Equatorial Guinea and Israel; and
- higher operating costs associated with the Aseng field which began producing in November 2011;

offset by

- the sale of certain Oklahoma and Illinois Basin assets in 2010, which had higher lease operating costs.

Production and Ad Valorem Tax Expense In the US, taxes increased in 2012 as compared with 2011 due to the enactment of the annual Marcellus Shale well impact fee by the Pennsylvania legislature in first quarter 2012. This enactment increased taxes approximately $8 million, of which approximately $4 million related to wells spud prior to 2012. Additionally, higher volumes for the Wattenberg area resulted in an increase of $15 million. This increase was offset by non-core onshore US property sales during 2012.

Production and ad valorem tax expense decreased in 2011 as compared with 2010 due to the sale of certain non-core Oklahoma and Illinois Basin assets in 2010 and natural field decline in the Mid-Continent area. This decrease was offset by higher production and ad valorem taxes in the DJ Basin due to increased production volumes and higher sales prices. Production and ad valorem tax expense for 2011 increased in China as compared with 2010 due to higher sales prices.

Transportation Expense Transportation expense increased in 2012 as compared with 2011. 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.

Transportation expense increased in 2011 as compared with 2010 due to higher sales volumes in the DJ Basin and new production from our Marcellus Shale producing properties acquired on September 30, 2011, offset by lower transportation expense in the deepwater Gulf of Mexico due to declining production.

Unit Rate Per BOE 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 production rate than our other projects, and the enactment of the Marcellus Shale well impact fee.

The unit rate of total production expense per BOE increased for 2011 as compared with 2010 primarily due to higher production tax rates on certain onshore US and China production, transportation charges related to Marcellus Shale producing properties and the startup of the Aseng field.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa [1]	Eastern Mediterranean [2]	Other Int'l, Corporate [3]
Year Ended December 31, 2012					
Dry Hole Cost	$ 155	$ 121	$ 34	$ —	$ —
Seismic	81	59	4	—	18
Exploration 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
Exploration Expense	94	22	7	2	63
Other	15	15	—	—	—
Total Exploration Expense	$ 277	$ 116	$ 67	$ 6	$ 88
Year Ended December 31, 2010					
Dry Hole Cost	$ 58	$ 54	$ 3	$ —	$ 1
Seismic	102	51	5	11	35
Exploration Expense	66	10	6	2	48
Other	16	15	—	—	1
Total Exploration Expense	$ 242	$ 130	$ 14	$ 13	$ 85

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone, and Senegal/Guinea-Bissau.

(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 2012 as compared with 2011 due to the following:

- US dry hole expense associated with the Deep Blue exploratory well (deepwater Gulf of Mexico) totaled $117 million. Although Deep Blue was successful in locating hydrocarbons, we decided not to develop the prospect due to near-term lease expiration as well as other considerations;
- dry hole expense in West Africa related to the Trema exploratory well, which found noncommercial quantities of hydrocarbons, totaled $32 million;
- 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. We relinquished our acreage;
- 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.

Oil and gas exploration expense increased in 2011 as compared with 2010 due to the following:

- US dry hole expense was associated with the Rocky Mountain area and the Redrock exploration well in the deepwater Gulf of Mexico, which we decided not to pursue for development due to the significant decline in natural gas prices;
- dry hole expense in West Africa related to the Kora-1 exploration well offshore Senegal/Guinea-Bissau and the Bwabe exploration well offshore Cameroon, which found noncommercial quantities of hydrocarbons;
- seismic expenditures related to acquisition of information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, offshore Nicaragua, offshore France, and offshore Cyprus; and
- increases in staff expense were due to new ventures mainly offshore Nicaragua and offshore France.

Exploration expense included stock-based compensation expense of $12 million in 2012, $11 million in 2011, and $10 million in 2010.

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

	Year Ended December 31,		
	2012	2011	2010
(millions, except unit rate)			
United States	$ 929	$ 732	$ 719
Equatorial Guinea	255	69	39
Israel	111	25	22
Other International, Corporate, and Other	75	52	39
Total DD&A Expense [1]	$ 1,370	$ 878	$ 819
Unit Rate per BOE [2]	$ 16.16	$ 11.32	$ 10.94

(1) DD&A expense includes accretion of discount on asset retirement obligations of $22 million in 2012, $13 million in 2011, and $13 million in 2010.

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

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

- higher sales volumes in the DJ Basin onshore US 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.

Changes in the unit rate per BOE for 2012 as compared with 2011 were due to changes in the mix of production, primarily due to volumes from the start-up of the Galapagos, Noa, Pinnacles and South Raton projects and a full year of production from Aseng, which have comparatively higher DD&A rates, and increased horizontal drilling activity.

Total DD&A expense increased for 2011 as compared with 2010 due to the following:

- higher sales volumes in the DJ Basin of our onshore US operations resulting from ongoing capital spending;
- higher sales volumes in Equatorial Guinea and the startup of the Aseng field which includes the Aseng FPSO in its depreciation base;
- higher costs associated with development activities in China; and
- the impact of negative reserves revisions at December 31, 2011, due to revised performance expectations in the North Sea and China;

partially offset by

- lower sales volumes in the deepwater Gulf of Mexico, Gulf Coast, and Mid-Continent areas of our US operations resulting from natural field decline.

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

	Year Ended December 31,		
	2012	2011	2010
G&A Expense (millions)	$ 384	$ 339	$ 273
Unit Rate per BOE [(1)]	4.53	4.37	3.65

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

G&A expense for 2012 increased as compared with 2011 primarily due to additional personnel and office space supporting growth in the Wattenberg and Marcellus Shale core areas 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 increased for 2011 as compared with 2010 primarily due to additional expenses relating to personnel, office costs and information technology costs in support of our major development and exploration projects 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 $48 million in 2012, $42 million in 2011 and $39 million in 2010. See Item 8. Financial Statements and Supplementary Data – Note 14. Stock-Based and Other Compensation Plans.

Gain on Divestitures Gain on divestitures was as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Gain on Divestitures	$ (154)	$ (25)	$ (113)

Gain on divestitures for 2012 is related to the sale of certain non-core onshore US assets. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Gain on divestitures for 2011 includes a $25 million gain on the transfer of assets and the associated PSC and electricity concession to the Ecuadorian government. Gain on divestitures for 2010 includes a $110 million gain on the sale of certain non-core assets in the Mid-Continent and Illinois Basin areas. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Asset Impairments Asset impairment expense was as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Asset Impairments	$ 104	$ 757	$ 144

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,		
	2012	2011	2010
(millions)			
Deepwater Gulf of Mexico Moratorium Expense	$ —	$ 18	$ 27
Electricity Generation Expense	—	26	39
Other (Income) Expense, Net	25	42	(2)
Total	$ 25	$ 86	$ 64

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,		
	2012	2011	2010
(millions)			
Gain on Commodity Derivative Instruments	$ (75)	$ (42)	$ (157)
Interest, Net of Amount Capitalized	125	65	72
Other Non-Operating (Income) Expense, Net	6	9	6
Total	$ 56	$ 32	$ (79)

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

Gain on Commodity Derivative Instruments We recognize all gains and losses on commodity derivative instruments in earnings in the period in which they occur. See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, below, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities and Note 15. Fair Value Measurements and Disclosures.

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

	Year Ended December 31,		
	2012	2011	2010
(millions, except per unit)			
Interest Expense	$ 276	$ 197	$ 139
Capitalized Interest	(151)	(132)	(67)
Interest Expense, Net	$ 125	$ 65	$ 72
Unit Rate per BOE [1]	$ 1.48	$ 0.84	$ 0.96

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

Interest expense prior to the reduction of capitalized interest increased $79 million from 2011 to 2012 due to 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.

Interest expense prior to the reduction of capitalized interest increased $58 million in 2011 as compared with 2010 resulting from a higher outstanding debt balance during the period and the interest associated with our 2011 public debt issuances. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility which was repaid with proceeds from our debt offering.

The increase of $19 million in the amount of interest capitalized in 2012 compared to 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.

The increase of $65 million in the amount of interest capitalized in 2011 compared to 2010 is due to higher work in progress amounts related to major long lead-time projects in the deepwater Gulf of Mexico, offshore West Africa, and Eastern Mediterranean and a higher weighted average interest rate due to our fixed rate senior unsecured note issuances in 2011, which impacted the average rate we pay on long-term debt.

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 7. 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, 2012, approximately 48% 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 $6 million in 2012, $8 million in 2011, and $15 million in 2010. See Item 8. Financial Statements and Supplementary Data – Note 14. Stock-Based and Other Compensation Plans.

Income Tax Provision The income tax provision was as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Income Tax Provision	$ 391	$ 90	$ 217
Effective Rate	28.8%	17.9%	25.6%

See Item 8. Financial Statements and Supplementary Data – Note 13. Income Taxes.

Discontinued Operations

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

	Year Ended December 31,		
	2012	2011	2010
millions			
Oil and Gas Sales	$ 208	$ 357	$ 309
Less:			
Production Expense	44	58	55
DD&A Expense	33	87	64
Other Expense, Net [(1)]	30	(3)	7
Income Before Income Taxes	101	215	183
Income Tax Expense	55	174	89
Operating Income, Net of Tax	46	41	94
Gain on Sale, Net of Tax	16	—	—
Discontinued Operations, Net of Tax	$ 62	$ 41	$ 94
Key Statistics:			
Daily Production			
Crude Oil & Condensate (MBbl/d)	5	8	10
Natural Gas (MMcf/d)	4	5	6
Average Realized Price			
Crude Oil & Condensate (Per Bbl)	$ 112.94	112.97	80.24
Natural Gas (Per Mcf)	8.62	8.11	5.35

(1) Includes exploration expense of $27 million in 2012 related to the Selkirk field. During 2012, the nearby Bligh well, a potential co-development candidate for Selkirk, was drilled. Bligh encountered hydrocarbons but disappointingly tight non-commercial reservoirs. Therefore, we determined that Selkirk 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. Acquisitions and Divestitures.

PROVED RESERVES

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

	Year Ended December 31,		
	2012	2011	2010
(MMBoe)			
Proved Reserves Beginning of Year	1,209	1,092	820
Revisions of Previous Estimates	(97)	(50)	5
Extensions, Discoveries and Other Additions	218	180	360
Purchase of Minerals in Place	—	68	47
Sale of Minerals in Place	(57)	—	(61)
Production	(89)	(81)	(79)
Proved Reserves End of Year	1,184	1,209	1,092

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, 2012 included a negative revision of 94 MMBoe due to our decision to terminate the legacy vertical drilling program in Wattenberg and focus on the horizontal development of the Niobrara; 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;
- changes for the year ended December 31, 2011 include a negative revision of 28 MMBoe, due primarily to reclassifications of proved undeveloped reserves in Wattenberg 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; and
- changes for the year ended December 31, 2010 included a positive revision of 43 MMBoe due to higher year-end commodity prices, a negative revision of 30 MMBoe due to reclassifications of proved undeveloped reserves to probable reserves as a result of the SEC's five year development rule, a negative revision of 7 MMBoe due to a change in the likelihood that the Noa field, offshore Israel, would be pursued for development, and a negative revision of 2 MMBoe due to well performance.

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, 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, 56 MMBoe related to ongoing development of the Marcellus Shale, 7 MMBoe related to the ongoing appraisal of Tamar, and 6 MMBoe for other projects;
- 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 Tamar due to appraisal activities, and 3 MMBoe for other projects; and
- changes for the year ended December 31, 2010 included an increase of 48 MMBoe, which were primarily driven by the execution of low-risk development projects onshore in Wattenberg and the Rocky Mountain area, an increase of 286 MMBoe related to the initial recording of reserves for the Tamar field offshore Israel, and an increase of approximately 27 MMBoe related to the initial recording of reserves for the Alen field, offshore Equatorial Guinea.

We expect that a significant portion of future reserves additions will come from our major development projects at the DJ Basin, Marcellus Shale, Gunflint, Tamar and Leviathan and from 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 Marcellus Shale asset acquisition in 2011; and
- the DJ Basin asset acquisition in 2010.

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

- the sale of non-core, onshore US assets in the Kansas, western Oklahoma, west Texas and Wyoming areas and the North Sea in 2012; and
- the sale of non-core assets in the Mid-Continent and Illinois Basin areas in 2010.

Sales of Minerals in Place also included a reduction in natural gas reserves due to the Ecuadorian government's termination of our Block 3 PSC in November 2010. See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

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 and monetize our major development projects, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the 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 maintaining the capability to execute a robust exploration program and 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 also 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.

Our current line-up of major development projects, as well as our planned exploration and appraisal drilling activities, will result in capital expenditures exceeding cash flows from operating activities over the near term. The amount by which capital investment will exceed operating cash flows depends on our success in sanctioning future development projects, the results of our exploration activities, and new business opportunities. To support our investment program, we expect that higher production resulting from our accelerated horizontal Niobrara development program combined with new production from Tamar and Alen will result in an increase in cash flows which will be available to meet a substantial portion of future capital requirements. In addition, our current liquidity level and strong balance sheet provide flexibility. We believe that we are well-positioned to fund our long-term growth plans. See Available Liquidity, below.

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 financial and technical challenges for us due to the large-scale development requirements. Potential development scenarios may include the construction of LNG terminals, floating LNG, subsea pipeline or other options. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. We have announced a potential strategic partner for Leviathan, Woodside, who could provide midstream expertise as well as LNG project execution and marketplace expertise. We are in the process of negotiating a definitive agreement. See Items 1. and 2. Business and Properties - Acquisition and Divestiture Activities.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash on hand, cash flows from operations, available borrowing capacity under our credit facility, and proceeds from sales of non-core properties, such as certain onshore US and North Sea properties in 2012. We may also access debt and/or capital markets for additional financing, such as an issuance of long-term debt or project finance, for our large development projects. We exercised our option to increase our Credit Facility's overall commitment amount by an additional $1.0 billion, on September 28, 2012. See *Credit Facility* below. See also Item 1A. Risk Factors - *Unavailability of capital resources at reasonable cost could have a negative impact on our liquidity and limit our growth.*

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. We spread the $1.3 billion acquisition cost over a three-year period, beginning at closing. The $2.1 billion CONSOL Carried Cost Obligation is expected to extend over a multi-year period and is capped at $400 million maximum 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 suppressed natural gas price, we did not make any payments towards the CONSOL Carried Cost Obligation in 2012 and expect the carry to remain suspended in 2013. See Off-Balance Sheet Arrangements below. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

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

	December 31,		
	2012	2011	2010
(millions, except percentages)			
Cash and Cash Equivalents	$ 1,387	$ 1,455	$ 1,081
Amount Available to be Borrowed Under Credit Facility [1]	4,000	3,000	1,750
Total Liquidity	$ 5,387	$ 4,455	$ 2,831
Total Debt [2]	$ 4,123	$ 4,495	$ 2,279
Total Shareholders' Equity	8,258	7,265	6,848
Ratio of Debt-to-Book Capital [3]	33%	38%	25%

(1) See *Credit Facility* below.

(2) Total debt includes Aseng FPSO lease obligation and remaining CONSOL installment payments 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 $1.4 billion in cash and cash equivalents at December 31, 2012, compared with approximately $1.5 billion at December 31, 2011. At December 31, 2012 our cash was primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $1.0 billion of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently expect to use a significant amount of cash during 2013 to fund international projects, including the planned developments in West Africa and the Eastern Mediterranean.

Credit Facility We have an unsecured revolving credit facility that matures on October 14, 2016. 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 combination 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 basis swaps. 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. Current period settlements on derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties.

None of our counterparty agreements contain margin requirements. Depending on the rules and definitions adopted by the CFTC and prudential regulators pursuant to the requirements of the Dodd-Frank Act, we could be required to post significant amounts of collateral with our dealer counterparties for our derivative transactions. A sudden margin call driven by an increase in commodity prices 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. See Item 1A. Risk Factors – *Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.*

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, 2012, the fair value of our commodity derivative assets was $84 million and the fair value of our commodity derivative liabilities was $10 million (after consideration of netting clauses within our master agreements). See Item 1A. Risk Factors – *Commodity and interest rate hedging transactions may limit our potential gains* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments.*

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 10. Derivative Instruments and Hedging Activities.

US Fiscal Crisis Congress and the Administration have thus far been unable to resolve the country's long-term fiscal issues, particularly the debt ceiling and the federal budget deficit. Congress recently passed, and the President signed into law, a bill to suspend the debt ceiling until May 19, 2013. If the debt ceiling is not raised in a timely manner, the US could default on its debt and/or experience a reduction in its credit rating, and interest rates could rise. In addition, on March 1, 2013 mandatory across-the-board spending cuts go into effect, and by late March 2013, a new spending bill must be passed to fund the federal government.

Congress and the Administration are deeply divided over these issues and there is a lack of consensus as to whether deficit reductions should come from spending cuts, tax increases or a combination of both. In addition, the government has failed to address increasing entitlement costs. At this time, substantial uncertainty exists as to whether or how these matters will be resolved. Certain measures, if enacted too suddenly, could reduce economic growth and increase the risk of a recession. Actions to address the deficit could lead to measures that could increase the tax expense on oil and gas companies. See Item 1A. Risk Factors - *Our operations may be adversely affected by changes in the fiscal regimes and government policies and regulation of oil and gas development in the countries in which we operate* and *Failure to resolve long-term US fiscal issues, primarily the federal budget deficit and the debt ceiling, could have a negative impact on the economy, slowing growth and reducing demand for our products.*

European Debt Crisis The European debt crisis continues to have a negative impact on the European economy, with risks to the global financial system and overall global economy. Countries have raised taxes and reduced entitlements, but are still struggling to pay off their debts; and the major bailout fund, the European Stability Mechanism (ESM) has limited lending capacity. During 2012, Cyprus, a country where we currently have exploration and appraisal activities, became the fifth eurozone country requesting bailout. Some of the European banks are counterparties in our commodity hedging program and lenders in our credit facility. If these institutions receive credit downgrades, our internal risk guidelines could preclude further hedging activities with them. At this time, we believe our current balance sheet and financial flexibility enhance our ability to react to eurozone events as they unfold. See Item 1A. Risk Factors - *Our operations may be adversely affected by the European debt crisis.*

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.

The current uncertain economic and commodity price environment increases the risk of a sudden negative change in liquidity, which could impair a party's ability to perform under the terms of a contract. 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. 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. In conjunction with our negotiations with Woodside, we are assisting our current Leviathan partners to obtain appropriate financing for their share of development costs and considering providing a limited amount of financial backstop to them. A partner's inability to obtain financing could result in a delay of one of our joint development projects. See Item 1A. Risk Factors - *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.*

Credit enhancements have been obtained from some parties in the form of parental guarantees or letters of credit; 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.

Insurance Recoveries In May 2011, we ended drilling operations at the Leviathan-2 appraisal well location offshore Israel when we identified water flowing to the sea floor from the wellbore. Drilling did not reach the depth of the targeted gas intervals discovered in the Leviathan-1 well. The incident was a covered event under our well control insurance. At this time, we expect to recover the costs from insurance, subject to a deductible. We do not expect any delays in the insurance claim recovery process to have a significant impact on our cash flows or liquidity. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

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 or letters of credit, 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 – *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments* 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,		
	2012	2011	2010
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 2,933	$ 2,170	$ 1,946
Investing Activities	(2,527)	(3,113)	(1,779)
Financing Activities	(474)	1,317	(100)
(Decrease) Increase in Cash and Cash Equivalents	$ (68)	$ 374	$ 67

Operating Activities Net cash provided by operating activities for 2012 increased $763 million, or 35% as compared with 2011. Higher liquids sales volumes and slightly higher crude oil prices were offset by decreases in natural gas sales volumes and prices and 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 2011 increased $224 million, or 12% as compared with 2010. 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 $3.7 billion in 2012, representing an increase of $529 million as compared with 2011, primarily due to increased major project 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, representing an increase of $847 million as compared with 2010. A significant portion of the spending was related to our major development projects. We received $77 million total proceeds from asset divestitures.

In 2010, our capital spending totaled $2.3 billion, including $458 million spent on the DJ Basin asset acquisition. We received $564 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 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 revolving 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).

In 2010, net cash of $100 million was used in financing activities. Funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($72 million). Funds were used for net repayments under our revolving credit facility ($32 million). We paid cash dividends on our common stock ($127 million), and repurchased shares of our common stock ($13 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,		
	2012	2011	2010
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition [1]	$ 96	$ 982	$ 305
Proved Property Acquisition [2]	—	392	352
Exploration	572	493	343
Development	2,847	2,200	1,520
Corporate and Other	70	196	121
Total	$ 3,585	$ 4,263	$ 2,641
Other			
Investment in Equity Method Investee [3]	$ 41	$ 69	$ —
Increase in FPSO Lease Obligation [4]	—	66	266

(1) Unproved property acquisition cost for 2012 includes $85 million primarily related to additional acreage in the DJ Basin and other onshore US lease acquisitions, $25 million related to our entry into a farmout agreement offshore Falkland Islands, $28 million in bonuses paid on deepwater Gulf of Mexico lease blocks acquired in the June 2012 lease sale, $3 million related to our entry into a license offshore Sierra Leone (West Africa), 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 our position offshore Senegal/Guinea-Bissau (the AGC Profond block), $31 million related to additional acreage in the DJ Basin, and $58 million related to onshore US lease acquisitions.
Unproved property acquisition cost for 2010 includes $146 million related to the DJ Basin asset acquisition, $38 million for deepwater Gulf of Mexico lease blocks, and the remainder for other onshore US lease acquisitions primarily in Wattenberg.

(2) Proved property acquisition cost includes $386 million related to the Marcellus Shale asset acquisition in 2011 and $352 million related to DJ Basin asset acquisition in 2010.

(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 progress on the Aseng FSPO, which went into service during the fourth quarter of 2011.

Excluding the impact of the Marcellus Shale acquisition in 2011, total expenditures increased in 2012 as compared with 2011 due 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.

Total expenditures in 2011 increased as compared with 2010 due to major development project expenditures and the Marcellus Shale asset acquisition. In addition, exploration activity increased.

Asset Divestitures In 2012, non-core asset divestitures generated cash proceeds of approximately $1.2 billion. In 2011, we transferred certain assets to the Ecuadorian government for cash proceeds of $73 million. In 2010, we sold certain non-core assets in the Mid-Continent and Illinois Basin areas for cash proceeds of $552 million.

Risk and Insurance Program

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering, fire, loss of well control, 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, comprehensive general 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 revise our insurance program accordingly. We have limited or no insurance coverage for certain risks such as war or political risk. In addition, coverage is generally limited or not available to us for pollution events that are considered gradual.

In certain international locations (including Israel and Equatorial Guinea) we carry business interruption insurance for loss of production income arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In Israel, we carry political violence and terrorism coverage in addition to coverages for business risk. Additionally, as being part of critical national infrastructure, Mari-B and Tamar are included in a special funding coverage under the government of Israel property tax fund.

In the Gulf of Mexico, we self-insure for windstorm related exposures. Our Gulf of Mexico assets are primarily subsea operations; therefore, our direct windstorm exposure is limited. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. We believe it is more cost-effective for us to self-insure these assets.

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 $700 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. This protection consists of more than $500 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 providers contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusions 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, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We anticipate that ongoing changes in the types of coverage available in the insurance market may result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident of 2010 and other recent international incidents and their impact on the insurance market and our overall risk profile. We anticipate that, at a minimum, less effective liability coverage will be available at a higher cost. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Our business entails inherent risks. 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 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 $3.8 billion (excluding the Aseng FPSO lease obligation) at December 31, 2012, with maturities ranging from 2013 to 2097. Our principal source of liquidity is an unsecured revolving credit facility that matures October 14, 2016. We did not engage in any short-term borrowing arrangements in 2012 or 2011 other than amounts drawn and repaid under our credit facility for working capital purposes during the normal course of business.

Credit Facility The Credit Facility, after giving effect to the increase in the overall commitment as of September 28, 2012, (i) provides for an initial commitment of $4.0 billion, (ii) will mature on October 14, 2016, (iii) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (iv) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (v) 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.

At December 31, 2012, 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 under provision (iv) above for working capital purposes. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

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.

CONSOL Installment Payments The first of two $328 million annual installment payments was paid on September 30, 2012. The remaining installment payment has been discounted at our incremental borrowing rate, a discount rate of 1.79%, and is due on September 30, 2013. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

Public Debt Offerings We occasionally enter into public debt offerings to increase our liquidity. 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 revolving credit facility, fund our exploration and development programs and for general corporate purposes.

FPSO Lease Obligation We account for our Aseng FPSO lease agreement as a capital lease. We paid $45 million under our lease obligation in 2012, compared with $3 million in 2011. The Aseng FPSO completed the construction phase and we commenced production at Aseng in November 2011.

Fixed-Rate Debt Our outstanding fixed-rate debt (excluding the Aseng FPSO lease obligation) totaled approximately $3.8 billion at December 31, 2012. The weighted average interest rate on fixed-rate debt was 5.89%, with maturities ranging from 2013 to 2097. Approximately 14% of our fixed rate debt matures within the next five years. See Item 8. Financial Statements and Supplementary Data – Note 12. 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, such as the issuance of our 6% senior unsecured notes in 2011, 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 10. Derivative Instruments and Hedging Activities.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital decreased to 33% at December 31, 2012 from 38% at December 31, 2011. Significant changes in our financial position included the following:

- $361 million reduction in debt due to the first installment payment to CONSOL as well as payment under our FPSO lease obligation; and
- $1.0 billion increase in shareholders' equity from current year net income;

offset by:

- $164 million decrease in shareholders' equity from dividends paid.

Cash Interest Payments We made cash interest payments of $259 million in 2012, $164 million in 2011, and $133 million in 2010.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $56 million in 2012, $38 million in 2011, and $47 million in 2010. 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 91 cents per common share in 2012, 80 cents per common share in 2011, and 72 cents per common share in 2010. On January 28, 2013, the Board of Directors declared a quarterly cash dividend of 25 cents per common share, which will be paid February 25, 2013 to shareholders of record on February 11, 2013. 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 141,000 shares with a total value of $13 million in 2012, 187,000 shares with a total value of $17 million in 2011, and 168,000 shares with a total value of $13 million in 2010.

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, 2012, 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. Therefore, specific payment dates for the funding of the CONSOL Carried Cost Obligation cannot be determined at this time. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. Based on the December 31, 2012 Henry Hub natural gas price strip, we forecast the obligation will be suspended through the 2013 fiscal year. See Items 1. and 2. Business and Properties - Title to Properties.

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	2013	2014 and 2015	2016 and 2017	2018 and beyond
(millions)					
Long-Term Debt [1]	$ 3,812	$ 328	$ 200	$ —	$ 3,284
Interest Payments [2]	3,249	229	419	417	2,184
FPSO Lease Payments [3]	413	72	142	90	109
Drilling and Equipment Obligations [4]					
United States	140	84	56	—	—
International	420	164	171	85	—
Purchase Obligations [5]	646	491	139	16	—
Transportation and Gathering [6]	731	81	164	175	311
Operating Lease Obligations [7]	543	47	94	100	302
Other Liabilities [8]					
Asset Retirement Obligations [9]	402	69	74	12	247
Commodity Derivative Instruments [10]	10	7	3	—	—
Total Contractual Obligations	$ 10,366	$ 1,572	$ 1,462	$ 895	$ 6,437

(1) Long-term debt excludes our Aseng FPSO lease obligation. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

(2) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2012. See Item 8. Financial Statements and Supplementary Data – Note 12. 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 12. 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 20. 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 20. 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 20. 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 20. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $229 million and accrued benefit costs of $116 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 14. Stock-Based and Other Compensation Plans.

(9) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data – Note 11. Asset Retirement Obligations.

(10) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2012. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2012. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

As of December 31, 2012, we accrued approximately $22 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 $68 million at December 31, 2012.

Other

Income Taxes We made cash payments for income taxes, net of refunds, of $168 million in 2012, $288 million in 2011, and $173 million in 2010.

Contingencies Payments to settle legal proceedings totaled approximately $12 million in 2012, $1 million in 2011, and $7 million in 2010. 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, including rule revisions designed to modernize the oil and gas company reserves reporting requirements, which we implemented effective December 31, 2009. 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 exploration 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 exploration well and subsequent sidetrack, we and our partners decided not to proceed with additional appraisal activities. At December 31, 2012, the balance of property, plant and equipment included $900 million of suspended exploratory well costs, $545 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 exploration wells. See Item 8. Financial Statements and Supplementary Data – Note 7. 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 at least semi-annually, at year-end and mid-year or 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 2012, 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 $104 million in 2012, $757 million in 2011 and $144 million in 2010 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 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 extract 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 periodically during the years ended December 31, 2012, 2011 and 2010 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, such as our DJ Basin asset acquisition in 2010. 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. Acquisitions and Divestitures.

Goodwill As of December 31, 2012, the consolidated balance sheet included $635 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, 2012, 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 2012, we sold certain non-core onshore US assets. Goodwill allocated to these assets sold totaled $61 million. See Item 8. Financial Statements and Supplementary Data – Note 9. Goodwill.

Derivative Instruments and Hedging Activities In order to mitigate the effects of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All commodity derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net receivable position with a fair value of $74 million at December 31, 2012. 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, 2012, we reported a $75 million mark-to-market gain 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 10. Derivative Instruments and Hedging Activities and Note 15. 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 $402 million at December 31, 2012. See Item 8. Financial Statements and Supplementary Data – Note 11. 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 2012 and as a result 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. In 2012, we also established a valuation allowance on our available foreign tax credit carried forward of $38 million with a net increase in deferred income tax expense.

As of December 31, 2012, the accumulated undistributed earnings of our foreign subsidiaries that have been permanently reinvested totaled approximately \$2.6 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 the development of our properties in West Africa and the Eastern Mediterranean. However, we estimate that a repatriation of \$1.0 billion as of December 31, 2012, if we had elected not to use the cash to fund international development, would have had a net cash tax impact of approximately \$100 million. This amount is net of estimated foreign tax credits. See Item 8. Financial Statements and Supplementary Data – Note 13. 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, 2012, 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 asset position with a fair value of \$74 million. Based on the December 31, 2012 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 asset by approximately \$20 million. A hypothetical price increase of \$0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately \$8 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 10. Derivative Instruments and Hedging Activities.

Interest Rate Risk

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

At December 31, 2012, we had approximately \$3.8 billion (excluding the Aseng FPSO lease obligation) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 5.89%. 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 12. 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, 2012, AOCL included \$25 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 10. 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, 2012, our cash and cash equivalents totaled approximately \$1.4 billion, approximately 56% 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, 2012 would result in a change in annual interest income of approximately \$2 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 losses from continuing operations were $1 million for 2012, compared with a loss of $8 million for 2011 and a gain of $3 million for 2010. 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

INDEX TO FINANCIAL STATEMENTS

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, 2012, 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*, 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, 2012, 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, 2012 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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 7, 2013 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 7, 2013

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, 2012, based on criteria established in *Internal Control - Integrated Framework* 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, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2012 and 2011, 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, 2012, and our report dated February 7, 2013 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 7, 2013

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

	Year Ended December 31,		
	2012	2011	2010
Revenues			
Oil, Gas and NGL Sales	$ 4,037	$ 3,179	$ 2,523
Income from Equity Method Investees	186	193	118
Other Revenues	—	32	72
Total Revenues	4,223	3,404	2,713
Costs and Expenses			
Production Expense	673	558	515
Exploration Expense	409	277	242
Depreciation, Depletion and Amortization	1,370	878	819
General and Administrative	384	339	273
Gain on Divestitures	(154)	(25)	(113)
Asset Impairments	104	757	144
Other Operating (Income) Expense, Net	25	86	64
Total Operating Expenses	2,811	2,870	1,944
Operating Income	1,412	534	769
Other (Income) Expense			
Gain on Commodity Derivative Instruments	(75)	(42)	(157)
Interest, Net of Amount Capitalized	125	65	72
Other Non-Operating (Income) Expense, Net	6	9	6
Total Other (Income) Expense	56	32	(79)
Income from Continuing Operations Before Income Taxes	1,356	502	848
Income Tax Provision	391	90	217
Income from Continuing Operations	965	412	631
Discontinued Operations, Net of Tax	62	41	94
Net Income	$ 1,027	$ 453	$ 725
Earnings Per Share, Basic			
Income from Continuing Operations	$ 5.43	$ 2.34	$ 3.61
Discontinued Operations, Net of Tax	0.34	0.23	0.54
Net Income	$ 5.77	$ 2.57	$ 4.15
Earnings Per Share, Diluted			
Income from Continuing Operations	$ 5.37	$ 2.31	$ 3.56
Discontinued Operations, Net of Tax	0.34	0.23	0.54
Net Income	$ 5.71	$ 2.54	$ 4.10
Weighted Average Number of Shares Outstanding			
Basic	178	176	175
Diluted	180	179	177

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

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

	Year Ended December 31,		
	2012	2011	2010
Net Income	$ 1,027	$ 453	$ 725
Other Items of Comprehensive Income (Loss)			
Oil and Gas Cash Flow Hedges			
Realized Losses Reclassified Into Earnings	—	—	20
Less Tax Benefit	—	—	(8)
Interest Rate Cash Flow Hedges			
Unrealized Change in Fair Value	—	23	(63)
Less Tax Provision (Benefit)	—	(8)	22
Net Change in Pension and Other	(20)	(17)	—
Less Tax Benefit	7	6	—
Other Comprehensive Income	(13)	4	(29)
Comprehensive Income	$ 1,014	$ 457	$ 696

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,387	$ 1,455
Accounts Receivable, Net	964	783
Other Current Assets	420	180
Total Current Assets	2,771	2,418
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	19,496	19,057
Property, Plant and Equipment, Other	344	294
Total Property, Plant and Equipment, Gross	19,840	19,351
Accumulated Depreciation, Depletion and Amortization	(6,289)	(6,569)
Total Property, Plant and Equipment, Net	13,551	12,782
Goodwill	635	696
Other Noncurrent Assets	597	548
Total Assets	$ 17,554	$ 16,444
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,508	$ 1,343
Other Current Liabilities	1,024	925
Total Current Liabilities	2,532	2,268
Long-Term Debt	3,736	4,100
Deferred Income Taxes, Noncurrent	2,218	2,059
Other Noncurrent Liabilities	810	752
Total Liabilities	9,296	9,179
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 and $3.33 1/3 per share; 500 Million and 250 Million Shares Authorized; 198 Million and 197 Million Shares Issued, Respectively	2	656
Additional Paid in Capital	3,304	2,497
Accumulated Other Comprehensive Loss	(113)	(100)
Treasury Stock, at Cost; 19 Million Shares	(648)	(638)
Retained Earnings	5,713	4,850
Total Shareholders' Equity	8,258	7,265
Total Liabilities and Shareholders' Equity	$ 17,554	$ 16,444

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

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

	Year Ended December 31,		
	2012	2011	2010
Cash Flows From Operating Activities			
Net Income	$ 1,027	$ 453	$ 725
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,403	965	883
Asset Impairments	104	759	144
Dry Hole Cost	182	105	58
Deferred Income Taxes	109	(81)	71
Dividends (Income) from Equity Method Investees, Net	7	30	21
Unrealized (Gain) Loss on Commodity Derivative Instruments	(109)	22	(70)
Gain on Divestitures	(72)	(25)	(113)
Stock Based Compensation	65	58	54
Other Adjustments for Noncash Items Included in Income	83	40	15
Changes in Operating Assets and Liabilities			
(Increase) in Accounts Receivable	(130)	(249)	(86)
(Increase) Decrease in Other Current Assets	(45)	7	18
Increase in Accounts Payable	237	3	234
Increase in Current Income Taxes Payable	64	37	31
Increase in Other Current Liabilities	18	38	3
Other Operating Assets and Liabilities, Net	(10)	8	(42)
Net Cash Provided by Operating Activities	2,933	2,170	1,946
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(3,650)	(2,594)	(1,885)
Marcellus Shale Asset Acquisition	—	(527)	—
DJ Basin Asset Acquisition	—	—	(458)
Additions to Equity Method Investments	(41)	(69)	—
Proceeds from Divestitures	1,160	77	564
Other	4	—	—
Net Cash Used in Investing Activities	(2,527)	(3,113)	(1,779)
Cash Flows From Financing Activities			
Exercise of Stock Options	56	38	47
Excess Tax Benefits from Stock-Based Awards	25	15	25
Dividends Paid, Common Stock	(164)	(143)	(127)
Purchase of Treasury Stock	(13)	(17)	(13)
Proceeds from Credit Facilities	150	520	760
Repayment of Credit Facilities	(150)	(870)	(792)
Repayment of CONSOL Installment Loan	(328)	—	—
Proceeds from Issuance of Senior Long-Term Debt, Net	—	1,828	—
Settlement of Interest Rate Derivative Instrument	—	(40)	—
Repayment of Capital Lease Obligation	(45)	(3)	—
Other	(5)	(11)	—
Net Cash Provided By (Used in) Financing Activities	(474)	1,317	(100)
Increase (Decrease) in Cash and Cash Equivalents	(68)	374	67
Cash and Cash Equivalents at Beginning of Period	1,455	1,081	1,014
Cash and Cash Equivalents at End of Period	$ 1,387	$ 1,455	$ 1,081

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

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

	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2009	$ 645	$ 2,260	$ (75)	$ (615)	$ 3,942	$ 6,157
Net Income	—	—	—	—	725	725
Stock-based Compensation Expense	—	54	—	—	—	54
Exercise of Stock Options	5	42	—	—	—	47
Tax Benefits Related to Exercise of Stock Options	—	25	—	—	—	25
Cash Dividends (72 cents per share)	—	—	—	—	(127)	(127)
Purchase of Treasury Stock	—	—	—	(13)	—	(13)
Rabbi Trust Shares Sold	—	5	—	4	—	9
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	—	—	12	—	—	12
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	—	—	(41)	—	—	(41)
Net Change in Other	1	(1)	—	—	—	—
December 31, 2010	$ 651	$ 2,385	$ (104)	$ (624)	$ 4,540	$ 6,848
Net Income	—	—	—	—	453	453
Stock-based Compensation Expense	—	58	—	—	—	58
Exercise of Stock Options	3	35	—	—	—	38
Tax Benefits Related to Exercise of Stock Options	—	15	—	—	—	15
Cash Dividends (80 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	2	(2)	(11)	—	—	(11)
December 31, 2011	$ 656	$ 2,497	$ (100)	$ (638)	$ 4,850	$ 7,265
Net Income	—	—	—	—	1,027	1,027
Stock-based Compensation Expense	—	65	—	—	—	65
Exercise of Stock Options	2	54	—	—	—	56
Tax Benefits Related to Exercise of Stock Options	—	25	—	—	—	25
Cash Dividends (91 cents per share)	—	—	—	—	(164)	(164)
Purchase of Treasury Stock	—	—	—	(13)	—	(13)
Rabbi Trust Shares Sold	—	7	—	3	—	10
Change in Par Value	(656)	656	—	—	—	—
Net Change in Other	—	—	(13)	—	—	(13)
December 31, 2012	$ 2	$ 3,304	$ (113)	$ (648)	$ 5,713	$ 8,258

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 8. 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 Vice President - Strategic Planning, Environmental Analysis & Reserves and certain members of senior management. See Supplemental Oil and Gas Information (Unaudited).

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, goodwill and asset retirement obligations, valuation allowances for receivables and deferred income tax assets, and valuation of derivative instruments, among others. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. Further 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 2011 and 2010 consolidated financial statements to reflect the operations of our North Sea geographical segment as discontinued, as well as to conform to the 2012 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 15. 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 6. Inventories.

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 14 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 as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

We recorded proved property impairment charges in 2012, 2011, and 2010. It is likely that other proved oil and gas properties could become impaired in the future if commodity prices decline. 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 extract 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. Acquisitions and Divestitures.

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 exploration 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 7. Capitalized Exploratory Well Costs.

Other Property Other property includes automobiles, trucks, airplanes, office furniture, computer equipment and other fixed assets such as building 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 three to ten 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 $151 million in 2012, $132 million in 2011, and $67 million in 2010.

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 11. 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, 2012. 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. See Note 9. Goodwill.

Derivative Instruments and Hedging Activities All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in our consolidated balance sheets as either an asset or liability and measured at fair value. 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.

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 10. 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 14. 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, 2012 represents unrecognized net actuarial loss, unrecognized prior service cost, and unrecognized net transition obligation remaining from the initial adoption of US GAAP for employers' accounting for pensions and other postretirement benefits. 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 14. 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 13. 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. See Note 16. 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 20. 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 17. 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 1/3 per share to $0.01 per share. See the Consolidated Statements of Shareholders' Equity.

Recently Issued Accounting Standards In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual and interim periods beginning after December 15, 2011. As of March 31, 2012, we have adopted the provisions of ASU 2011-04, which did not impact our consolidated financial statements. The only impact was to our fair value disclosures. See Note 15. Fair Value Measurements and Disclosures.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on our financial position and results of operations.

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Other Revenues [1]	—	32	72
Production Expense			
Lease Operating Expense	$ 431	$ 346	$ 329
Production and Ad Valorem Taxes	151	146	125
Transportation Expense	91	66	61
Total	$ 673	$ 558	$ 515
Other Operating Expense, Net			
Deepwater Gulf of Mexico Moratorium Expense [2]	$ —	$ 18	$ 27
Electricity Generation Expense [1]	—	26	39
Other, Net	25	42	(2)
Total	$ 25	$ 86	$ 64
Other Non-Operating (Income) Expense, Net			
Deferred Compensation Expense [3]	$ 6	$ 8	$ 15
Interest Income [4]	(1)	(8)	(7)
Other (Income) Expense, Net	1	9	(2)
Total	$ 6	$ 9	$ 6

(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.
(4) Interest income for 2010 includes $3 million related to the refund of deepwater Gulf of Mexico royalties.

Additional balance sheet information is as follows:

	December 31,	
	2012	2011
(millions)		
Accounts Receivable, Net		
Commodity Sales	$ 349	$ 356
Joint Interest Billings	486	313
Other	139	123
Allowance for Doubtful Accounts	(10)	(9)
Total	$ 964	$ 783
Other Current Assets		
Inventories, Current	$ 90	$ 78
Commodity Derivative Assets, Current	63	10
Deferred Income Taxes, Net, Current [(1)]	106	41
Probable Insurance Claims [(2)]	45	15
Assets Held for Sale [(3)]	45	—
Prepaid Expenses and Other Assets, Current	71	36
Total	$ 420	$ 180
Other Noncurrent Assets		
Equity Method Investments	$ 367	$ 329
Mutual Fund Investments	103	99
Commodity Derivative Assets, Noncurrent	21	37
Other Assets, Noncurrent	106	83
Total	$ 597	$ 548
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 113	$ 121
Commodity Derivative Liabilities, Current	7	76
Income Taxes Payable	203	127
Asset Retirement Obligations, Current	69	33
Interest Payable	55	56
CONSOL Installment Payment, Net [(4)]	324	324
Current Portion of FPSO Lease Obligation	48	45
Liabilities Associated with Assets Held for Sale [(3)]	12	—
Other Liabilities, Current	193	143
Total	$ 1,024	$ 925
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 229	$ 222
Asset Retirement Obligations, Noncurrent	333	344
Accrued Benefit Costs, Noncurrent [(5)]	116	88
Commodity Derivative Liabilities, Noncurrent	3	7
Other Liabilities, Noncurrent	129	91
Total	$ 810	$ 752

(1) Increase from December 31, 2011 is due to reclassification of deferred income tax assets from long-term to short-term as certain foreign entities are estimated to begin utilizing net operating loss carryforwards in 2013.

(2) Amounts represent the costs incurred to date of the Leviathan-2 appraisal well and expected well abandonment costs in excess of the insurance deductible less insurance proceeds received to date. See Note 11. Asset Retirement Obligations.

(3) Assets held for sale consist primarily of North Sea oil and gas properties, and liabilities associated with assets held for sale consists primarily of asset retirement obligations. See Note 3. Acquisitions and Divestitures.

(4) See Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

(5) Amount includes liabilities accrued under our defined benefit pension plan, restoration plan, and other postretirement benefit plans. See Note 14. Stock-Based and Other Compensation Plans.

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 107	$ 32	$ 66
Income Taxes Paid, Net	168	288	173
Non-Cash Financing and Investing Activities			
Increase in CONSOL Installment Payments, Net of Discount [1]	—	639	—
Increase in FPSO Lease Obligation [1]	—	66	266

(1) See Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

Note 3. Acquisitions and Divestitures

Sale of North Sea Properties On August 13, 2012, we closed the sale of our 30% non-operated working interest in the Dumbarton and Lochranza fields, located in the UK sector of 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.

We continue to market our remaining North Sea properties. As of December 31, 2012, 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 hydrocarbons but disappointingly tight non-commercial reservoirs. 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,		
	2012	2011	2010
(millions)			
Oil and Gas Sales	$ 208	$ 357	$ 309
Income Before Income Taxes	101	215	183
Income Tax Expense	55	174	89
Operating Income, Net of Tax	46	41	94
Gain on Sale, Net of Tax	16	—	—
Discontinued Operations, Net of Tax	$ 62	$ 41	$ 94

Sale of Onshore US Properties During the third quarter of 2012, we closed the sales of certain crude oil and natural gas properties in Kansas, western Oklahoma, western Texas, and the Texas Panhandle with an effective date of April 1, 2012. Additionally, in June 2012, we closed the sale of non-core assets located in Wyoming. The information regarding the assets sold is as follows:

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

We continue to market certain non-core onshore US properties. However, none of these assets met the criteria for reclassification as an asset held-for-sale at December 31, 2012.

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 have paid a total of $938 million as of December 31, 2012, and the remainder is due September 30, 2013. See Note 12. 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 is currently suspended due to low natural gas prices.

As a result of the transaction, we recorded the following:

	December 31, 2012
(millions)	
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 On November 25, 2010, the government of Ecuador terminated the Block 3 PSC (100% working interest) with our subsidiary, EDC Ecuador Ltd. as we had not negotiated a service contract on Block 3 in accordance with the terms of a newly enacted hydrocarbon law. The hydrocarbon law aimed to change current production-sharing arrangements into service contracts and provided for renegotiation of certain contracts.

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. We did not consider the property disposition material for discontinued operations presentation.

DJ Basin Asset Acquisition In March 2010, we acquired substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for $498 million. The acquisition included properties located in the DJ Basin, one of our core operating areas. The total purchase price was allocated to the proved and unproved properties acquired based on fair values at the acquisition date.

The total purchase price and allocation of the total purchase price are as follows:

	December 31, 2010
(millions)	
Total Purchase Price	
Cash Paid	$ 458
Net Liabilities Assumed	40
Total	$ 498
Allocation of Total Purchase Price	
Proved Oil and Gas Properties	$ 352
Unproved Oil and Gas Properties	146
Total	$ 498

Sale of Onshore US Assets In August 2010, we sold non-core assets in the Mid-Continent and Illinois Basin areas. Information regarding the assets sold is as follows:

		Year Ended December 31,
		2010
(millions)		
Cash Proceeds	$	552
Less		
Net Book Value of Assets Sold		(394)
Goodwill Allocated to Assets Sold		(61)
Asset Retirement Obligations Associated with Assets Sold		10
Other Closing Adjustments		3
Gain on Asset Sale	$	110

Note 4. Asset Impairments

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

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Piceance (Onshore US)	$ 39	$ 487	$ —
South Raton (Deepwater Gulf of Mexico)	34	—	—
Mari-B, Noa, Pinnacles (Offshore Israel)	31	—	—
East Texas (Onshore US)	—	128	—
Tri-State (Onshore US)	—	121	—
Iron Horse (Onshore US)	—	15	89
Other Onshore US Properties	—	6	—
New Albany Shale (Onshore US)	—	—	19
Noa/Noa South (Offshore Israel)	—	—	25
Raton (Deepwater Gulf of Mexico)	—	—	6
Main Pass (Gulf of Mexico Shelf)	—	—	5
Total	$ 104	$ 757	$ 144

2012 Asset Impairments Due to recent declines in realized natural gas prices associated with our Piceance development, onshore US, and recent 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. The discounted cash flow models 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.

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 developments 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.

2010 Asset Impairments Due to declines in natural gas prices and recent drilling results, we determined that the carrying amount of our onshore US development at Iron Horse was not recoverable from future cash flows and, therefore, was impaired. We also recorded impairments of our non-core, New Albany Shale assets which had been reclassified to held-for-sale; our deepwater Gulf of Mexico development at Raton, primarily due to declines in natural gas prices; a Gulf of Mexico shelf asset; and our investment in the Noa/Noa South development, offshore Israel. At December 31, 2010, we believed that it was less likely that Noa would be pursued for development due to near-term capability at the Mari-B field and the longer-term outlook from our discoveries at Tamar and Leviathan. During 2011, due to unexpected natural gas supply disruptions into Israel, we decided to develop Noa/Noa South. The Iron Horse, Raton and Gulf of Mexico shelf assets were written down to their estimated fair values, which were determined using discounted cash flow models, as described above. The New Albany shale assets were written down to anticipated sales proceeds less costs to sell.

See also Note 15. 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,		
	2012	2011	2010
(millions)			
Balance, Beginning of Period	$ 9	$ 27	$ 31
Changes			
Changes in Ecuador Receivable, Net[1]	—	(19)	(6)
Other Changes	1	1	2
Net Changes	1	(18)	(4)
Balance, End of Period	$ 10	$ 9	$ 27

(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. Acquisitions and Divestitures.

Note 6. Inventories

Inventories consisted of the following:

	December 31,	
	2012	2011
(millions)		
Materials and Supplies	$ 68	$ 56
Crude Oil	22	22
Total	$ 90	$ 78

Note 7. 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,		
	2012	2011	2010
(millions)			
Capitalized Exploratory Well Costs, Beginning of Period	$ 696	$ 466	$ 463
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	360	322	161
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(18)	(55)	(155)
Capitalized Exploratory Well Costs Charged to Expense (1)	(114)	(37)	(3)
Other (2)	(24)	—	—
Capitalized Exploratory Well Costs, End of Period	$ 900	$ 696	$ 466

(1) Amount primarily represents Deep Blue (deepwater Gulf of Mexico) exploratory well costs capitalized prior to December 31, 2012. Although hydrocarbons were found in both the initial exploration well and subsequent sidetrack, we and our partners decided not to proceed with additional appraisal activities.

(2) Amount relates to Selkirk (North Sea) exploratory well costs capitalized prior to December 31, 2012. During the fourth quarter of 2012, our Selkirk field, which is included in discontinued operations, was determined to be uneconomic for joint development and was charged to exploration expense. See Note 3. Acquisitions and Divestitures.

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,		
	2012	2011	2010
(millions)			
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 355	$ 318	$ 166
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	545	378	300
Balance at End of Period	$ 900	$ 696	$ 466
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	14	13	13

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of December 31, 2012:

		Suspended Since		
	Total	2011	2010	2009 & Prior
(millions)				
Country/Project:				
Offshore Equatorial Guinea				
Carla	$ 12	$ 12	$ —	$ —
Carmen	22	1	1	20
Diega	82	45	2	35
Felicita	35	2	2	31
Yolanda	18	1	1	16
Offshore Cameroon				
YoYo	45	5	2	38
Offshore Israel				
Leviathan	108	67	41	—
Leviathan-1 Deep	28	28	—	—
Tanin 1	31	31	—	—
Dolphin 1	22	22	—	—
Dalit	22	—	1	21
Offshore Cyprus				
Cyprus A-1	57	57	—	—
Deepwater Gulf of Mexico				
Gunflint	54	—	—	54
Other				
Projects of $10 million or less each	9	—	5	4
Total	$ 545	$ 271	$ 55	$ 219

Carla/Carmen/Diega Carla is a 2011 crude oil discovery on both Block O and I, Carmen is a 2009 crude oil discovery on Block O, and Diega is a 2008 condensate and oil discovery on Block I. We continue our appraisal program for Carla and Diega and have encountered hydrocarbons in multiple appraisal wells and side-tracks. We are currently evaluating regional development scenarios for these three discoveries, which includes possible sanctioning of Carla during 2013.

Felicita/Yolanda Felicita is a 2008 condensate and natural gas discovery on Block O. Yolanda is a 2008 condensate and natural gas discovery on Block I. We are currently evaluating regional natural gas development options for these discoveries.

YoYo YoYo is a 2007 natural gas and condensate discovery. During 2011 we acquired and processed additional 3-D seismic information and are continuing evaluations for future drilling potential. We are also working with the government of Cameroon to assess gas commercialization options.

Leviathan Leviathan is a 2010 natural gas discovery. During 2012, we continued to evaluate the discovery with the successful drilling of the Leviathan-3 appraisal well and spud the Leviathan-4 appraisal well. We have project and commercial teams in place and are in the process of screening multiple development concepts. Due to Leviathan's size, full field development, and realization of maximum economic value will require several development phases. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. Engineering design and planning work are currently underway for a potential first phase of development. In addition, we announced that the partners in the Leviathan Project had agreed in principle on a proposal to sell a 30% working interest in the Leviathan licenses to Woodside Energy Ltd. (Woodside). Woodside is Australia’s largest producer of LNG with over 25 years of experience and has strong working relationships with many potential customers in the Asian LNG markets.

Leviathan-1 Deep 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 well pressure 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 are continuing our evaluation of Leviathan-1 Deep and will integrate the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically to test the deep oil concept. We have secured a rig with the capabilities necessary to reach the target objective and plan to begin drilling an exploratory well in fourth quarter of 2013.

Tanin 1 Tanin 1 is a 2011 natural gas discovery located in the Alon A block, offshore Israel. We and our partners are currently reviewing alternatives for the development of reserves from this asset.

Dolphin 1 Dolphin 1 is a 2011 natural gas discovery located in the Hanna license, southwest of the Tamar gas field. We and our partners are currently reviewing alternatives for the development of reserves from this asset.

Dalit Dalit is a 2009 natural gas discovery. We and our partners are working on a development plan which would include tie-in to the Tamar platform and have submitted a development plan to the Israeli government.

Cyprus During the fourth quarter of 2011, we drilled a successful natural gas exploration well (A-1) in Block 12. We submitted an appraisal plan to the Cyprus government during July 2012 and are reviewing locations for appraisal drilling activities.

Gunflint Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. In July 2012, we drilled a successful Gunflint appraisal well. We plan to drill a second appraisal well targeting the south area of the reservoir during first quarter of 2013. Front-end conceptual studies have been completed, and we are working toward sanctioning of a scalable development project in 2013. We are currently targeting 2017 for production start-up utilizing a standalone facility. If we choose to connect to an existing third-party host, the project could have an accelerated completion schedule.

Note 8. 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, 2012, our retained earnings included $111 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $10 million higher than the underlying net assets of the investee at December 31, 2012. 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,	
	2012	2011
(millions)		
Equity Method Investments		
AMPCO	$ 137	$ 147
Alba Plant	93	96
CONE	121	72
Other	16	14
Total Equity Method Investments	$ 367	$ 329

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

	December 31, 2012	December 31, 2011
(millions)		
Balance Sheet Information		
Current Assets	$ 384	$ 374
Noncurrent Assets	902	827
Current Liabilities	348	360
Noncurrent Liabilities	24	16

	Year Ended December 31, 2012	2011	2010
(millions)			
Statements of Operations Information			
Operating Revenues	$ 1,173	$ 1,139	$ 809
Operating Expenses	361	335	296
Operating Income	812	804	513
Other (Income) Net	(5)	(12)	(12)
Income Before Income Taxes	817	816	525
Income Tax Provision	200	201	133
Net Income	$ 617	$ 615	$ 392

Note 9. Goodwill

Changes in the carrying amount of goodwill were as follows:

	December 31, 2012	December 31, 2011
(millions)		
Goodwill, Beginning Balance	$ 696	$ 696
Amount Allocated to Sale of Business [1]	(61)	—
Goodwill, Ending Balance	$ 635	$ 696

[1] See Note 3. Acquisitions and Divestitures.

Note 10. 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 include variable to fixed price commodity swaps, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap 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.

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 15. 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, 2012, 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, 2012							
2013	Swaps	NYMEX WTI	8,000	$ 89.63	$ —	$ —	$ —
2013	Swaps	Dated Brent	3,000	98.03	—	—	—
2013	Two-Way Collars	NYMEX WTI	5,000	—	—	95.00	115.00
2013	Three-Way Collars	NYMEX WTI	7,000	—	63.57	83.57	109.04
2013	Three-Way Collars	Dated Brent	26,000	—	82.50	100.93	126.63
2014	Swaps	NYMEX WTI	11,000	90.26	—	—	—
2014	Swaps	Dated Brent	10,000	105.14	—	—	—
2014	Three-Way Collars	NYMEX WTI	4,000	—	77.00	92.00	106.13
2014	Three-Way Collars	Dated Brent	11,000	—	85.45	99.09	128.40

As of December 31, 2012, 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, 2012							
2013	Swaps	NYMEX HH	60,000	$ 4.58	$ —	$ —	$ —
2013	Two-Way Collars	NYMEX HH	40,000	—	—	3.25	5.14
2013	Three-Way Collars	NYMEX HH	100,000	—	3.88	4.75	5.63
2014	Swaps	NYMEX HH	60,000	4.24	—	—	—
2014	Three-Way Collars	NYMEX HH	130,000	—	2.56	3.56	5.21

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, 2012		December 31, 2011		December 31, 2012		December 31, 2011	
	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	$ 63	Current Assets	$ 10	Current Liabilities	$ 7	Current Liabilities	$ 76
	Noncurrent Assets	21	Noncurrent Assets	37	Noncurrent Liabilities	3	Noncurrent Liabilities	7
Total		$ 84		$ 47		$ 10		$ 83

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

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Realized Mark-to-Market (Gain) Loss	$ 34	$ (64)	$ (87)
Unrealized Mark-to-Market (Gain) Loss	(109)	22	(70)
Total (Gain) Loss on Commodity Derivative Instruments	$ (75)	$ (42)	$ (157)

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		
	2012	2011	2010	2012	2011	2010
(millions)						
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships [(1)]						
Crude Oil	$ —	$ —	$ —	$ —	$ —	$ 19
Natural Gas	—	—	—	—	—	1
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	—	(23)	63	1	1	1
Total	$ —	$ (23)	$ 63	$ 1	$ 1	$ 21

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. All net derivative gains and losses that were deferred in AOCL as a result of previous cash flow hedge accounting, had been reclassified to earnings by December 31, 2010.

AOCL at December 31, 2012 included deferred losses of $25 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 $2 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 11. 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,	
	2012	2011
(millions)		
Asset Retirement Obligations, Beginning Balance	$ 377	$ 253
Liabilities Incurred	43	23
Liabilities Settled	(112)	(24)
Revision of Estimate	102	105
Accretion Expense	22	20
Other	(30)	—
Asset Retirement Obligations, Ending Balance	$ 402	$ 377

For the year ended December 31, 2012, liabilities incurred include $6 million for onshore US development, $8 million for deepwater Gulf of Mexico, and $30 million for offshore Israel. Liabilities settled in 2012 include $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 relate primarily to changes in estimated costs for future abandonment activities and include $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. Acquisitions and Divestitures.

For the year ended December 31, 2011, liabilities incurred were primarily due to the Marcellus Shale asset acquisition as well as additions for the Alen project in Equatorial Guinea and Lochranza project in the North Sea. Liabilities settled in 2011 related primarily to deepwater Gulf of Mexico and Gulf of Mexico shelf properties. Revisions in 2011 resulted from changes in estimated abandonment costs mainly in the DJ Basin and deepwater Gulf of Mexico.

Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 12. Long-Term Debt

Our debt consists of the following:

	December 31, 2012		December 31, 2011	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility, due October 14, 2016 [1]	$ —	—	$ —	—
CONSOL Installment Payments	328	1.79% [2]	656	1.76% [2]
FPSO Lease Obligation	311	—	355	—
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%
7¼% Senior Debentures, due August 1, 2097	84	7.25%	84	7.25%
Total	4,123		4,495	
Unamortized Discount	(15)		(26)	
Total Debt, Net of Discount	4,108		4,469	
Less Amounts Due Within One Year				
Current portion of CONSOL Installment Payment, net of discount	(324)		(324)	
FPSO Lease Obligation	(48)		(45)	
Long-Term Debt Due After One Year	$ 3,736		$ 4,100	

(1) Our Credit Agreement provides for a $4.0 billion unsecured revolving 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 $35 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 September 28, 2012, we exercised our option to increase our bank revolving credit facility (the Credit Facility) to $4.0 billion. The credit facility was previously committed in the amount of $3.0 billion as of December 31, 2011. Debt issuance costs of approximately $4 million were incurred and are being amortized to expense over the remaining term of the Credit Facility which will mature on October 14, 2016.

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, 2012, 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.

2011 Debt Offerings On February 18, 2011, we closed an offering of $850 million senior unsecured notes receiving net proceeds of $836 million, after deducting discount and underwriting fees. The notes are due March 1, 2041, and pay interest semi-annually at 6%. Total debt issuance costs of approximately $9 million were incurred and are being amortized to expense over the term of the notes. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility and the balance of the proceeds has been used for general corporate purposes.

On December 8, 2011, we closed an offering of $1.0 billion senior unsecured notes receiving net proceeds of $992 million, after deducting discount and underwriting fees. The notes are due December 15, 2021, and pay interest semi-annually at 4.15%. Total debt issuance costs of approximately $8 million were incurred and are being amortized to expense over the term of the notes. Approximately $400 million of the net proceeds were used to repay outstanding indebtedness under our revolving 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, which has been discounted at the prevailing market rates for similar debt instruments, is due on September 30, 2013 and has been reclassified to current liabilities as of December 31, 2012. See Note 3. Acquisitions and Divestitures and Note 15. Fair Value Measurements and Disclosures.

Aseng FPSO Lease Obligation We lease an FPSO used in the Aseng field, offshore Equatorial Guinea. The amount of the Aseng FPSO lease obligation is based on the discounted present value of future minimum lease payments, and therefore does not reflect future minimum lease payments. Amounts due within one year equal the amount by which the Aseng FPSO lease obligation is expected to be reduced during the next 12 months. See Note 20. Commitments and Contingencies for future Aseng FPSO lease payments.

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

	Debt Principal Payments
(millions)	
December 31, 2012	
2013	$ 328
2014	200
2015	—
2016	—
2017	—
Thereafter	3,284
Total	$ 3,812

Note 13. Income Taxes

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

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Domestic	$ 92	$ (537)	$ 234
Foreign	1,264	1,039	614
Total	$ 1,356	$ 502	$ 848

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

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Current Taxes			
Federal	$ 14	$ 11	$ 25
State	1	2	2
Foreign	143	155	97
Total Current	158	168	124
Deferred Taxes			
Federal	60	(130)	86
State	1	(3)	1
Foreign	172	55	6
Total Deferred	233	(78)	93
Total Income Tax Provision	$ 391	$ 90	$ 217
Effective Tax Rate	28.8%	17.9%	25.6%

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

	Year Ended December 31,		
	2012	2011	2010
(percentages)			
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	(4.9)	(13.3)	(4.8)
State Taxes, Net of Federal Benefit	0.2	(0.1)	0.4
Difference Between US and Foreign Rates	(4.9)	(7.0)	(1.2)
Foreign Exploration Loss	(3.8)	(4.2)	—
Change in Valuation Allowance	4.3	6.6	(2.7)
Oil Profits Tax - Israel	0.9	2.6	(1.9)
Tax Contingency	1.8	—	—
Other, Net	0.2	(1.7)	0.8
Effective Rate	28.8	17.9	25.6

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2012	2011
(millions)		
Deferred Tax Assets		
Loss Carryforwards	$ 235	$ 200
Employee Compensation & Benefits	134	164
Foreign Tax Credits	38	57
Other	81	86
Total Deferred Tax Assets	488	507
Valuation Allowance - Foreign Loss Carryforwards	(81)	(65)
Valuation Allowance - Foreign Tax Credits	(38)	(57)
Net Deferred Tax Assets	369	385
Deferred Tax Liabilities		
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,481)	(2,409)
Total Deferred Tax Liability	(2,481)	(2,409)
Net Deferred Tax Liability	$ (2,112)	$ (2,024)

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

	December 31,	
	2012	2011
(millions)		
Deferred Income Tax Asset - Current	$ 106	$ 41
Deferred Income Tax Liability - Current	—	(6)
Deferred Income Tax Liability - Noncurrent	(2,218)	(2,059)
Net Deferred Tax Liability	$ (2,112)	$ (2,024)

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, 2012. 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 $81 million in 2012, $65 million in 2011, and $70 million in 2010. The changes to the valuation allowance for the loss carryforwards between periods was attributable to changes in losses on projects in new venture activities which are not yet commercial.

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.

During 2011, we recorded a $57 million increase in the valuation allowance against our deferred tax asset for foreign tax credits. This deferred tax asset was fully offset by a valuation allowance because, based on our forecast of foreign tax credits, we did not believe it was more likely than not that the asset would be realized.

During 2010, we reversed a $28 million valuation allowance that had been established against a deferred tax asset of the same amount for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations and recorded a corresponding reduction in income tax expense.

Effective Tax Rate 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.

Our effective tax rate decreased in 2011 as compared with 2010. This decrease was due to the impact of higher equity method earnings in 2011 which had the effect of decreasing the 2011 rate. The decrease was partially offset by the change in the Israeli tax law discussed below. Additionally, in 2010, we reversed a $28 million valuation allowance, as discussed above, which reduced income tax expense. Finally, the rate for 2010 was increased by a nondeductible allocation of goodwill to assets sold.

Changes in Israeli Tax Law In March 2011, the Israeli government enacted the Petroleum Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. These changes increased our 2011 consolidated effective income tax rate by approximately 4%. There was no remeasurement of our deferred tax assets or liabilities as of December 31, 2010.

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2012, the accumulated undistributed earnings of the foreign subsidiaries that have been permanently reinvested were approximately $2.6 billion. No US taxes have been recorded on these earnings. Upon distribution of additional earnings 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 $685 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. - 2009, Equatorial Guinea - 2007, Israel - 2008, and China - 2006.

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:

	Year Ended December 31, 2012	
(millions)		
Unrecognized Tax Benefits, Beginning Balance	$	—
Additions for tax positions related to current year		(1)
Additions for tax positions of prior years		24
Reductions for tax positions of prior years		—
Settlements		—
Unrecognized Tax Benefits, Ending Balance	$	23

As of December 31, 2012, approximately $23 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, 2012 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, 2012, 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 14. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2012	2011	2010
(millions)			
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 48	$ 42	$ 39
Exploration Expense and Other	17	16	15
Total Stock-Based Compensation Expense	$ 65	$ 58	$ 54
Tax Benefit Recognized	$ (23)	$ (20)	$ (19)

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. On April 26, 2011, our stockholders approved the amendment and restatement of the 1992 Plan to increase the number of shares of our common stock authorized for issuance under the plan from 24 million to 31 million shares and to modify certain plan provisions. At December 31, 2012, 12,180,343 shares of our common stock were reserved for issuance, including 7,009,795 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 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 generally vest over three years. Shares of restricted stock time-vest 20% after year one, an additional 30% after year two and the remaining 50% after year three.

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 800,000. At December 31, 2012, 696,178 shares of our common stock were reserved for issuance, including 476,873 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 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (with the February 1 annual and the discretionary grants made to a non-employee director during any calendar year being limited to a combined maximum of 11,200 options). 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 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock per non-employee director on February 1 of each year, and discretionary awards by the Board of Directors (with the February 1 annual and the discretionary awards made to a non-employee director during any calendar year being limited to a combined maximum of 4,800 shares of restricted stock). 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 (10,000 stock options for the first calendar year of service and 5,000 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 years 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,		
	2012	2011	2010
(weighted averages)			
Expected Term (in Years)	5.7	5.7	5.6
Expected Volatility	37.0%	36.2%	35.4%
Risk-Free Rate	0.9%	2.2%	2.6%
Expected Dividend Yield	1.2%	1.1%	1.1%
Weighted Average Grant-Date Fair Value	$ 31.98	$ 30.17	$ 25.05

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, 2011	6,365,816	$ 59.47		
Granted	1,225,827	101.50		
Exercised	(1,265,231)	43.84		
Forfeited	(120,626)	93.95		
Outstanding at December 31, 2012	6,205,786	$ 70.27	6.2	$ 196
Exercisable at December 31, 2012	4,164,438	$ 58.34	5.1	$ 181

The total intrinsic value of options exercised was $72 million in 2012, $40 million in 2011, and $68 million in 2010.

As of December 31, 2012, $36 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 1.4 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards Restricted stock activity was as follows:

	Shares Subject to Service Conditions	Weighted Average Award Date Fair Value
		(per share)
Outstanding at December 31, 2011	979,257	$ 74.87
Awarded	481,858	101.50
Vested	(472,691)	64.63
Forfeited	(55,193)	92.03
Outstanding at December 31, 2012	933,231	$ 92.79

The total fair value of restricted stock that vested was $47 million in 2012, $57 million in 2011, and $43 million in 2010.

The weighted average award-date fair value of restricted stock awarded was $101.50 per share in 2012, $90.32 per share in 2011, and $75.07 per share in 2010.

Awards of time-vested restricted stock (shares subject to service conditions) were valued at the price of our common stock at the date of award.

As of December 31, 2012, $45 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 $17 million in 2012, $14 million in 2011, and $11 million in 2010.

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,	
	2012	2011
(millions, except share amounts)		
Rabbi Trust Assets		
Mutual Fund Investments	$ 84	$ 82
Noble Energy Common Stock (at Fair Value)	76	80
Total Rabbi Trust Assets	160	162
Liability Under Related Deferred Compensation Plan	$ 160	$ 162
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	746,672	848,940

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 15. 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, $33.44 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 700,000 shares, or 94%, of our common stock held in the plan at December 31, 2012 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next seven years. Distributions of 100,000 shares were made in each of 2012 and 2011. In addition, plan participants sold 2,268 shares of our common stock in 2012, 100 shares in 2011, and 100 shares in 2010. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $19 million in 2012, $17 million in 2011 and $17 million in 2010.

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 $6 million in 2012, $8 million in 2011 and $15 million in 2010.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. Deferred compensation liabilities of $70 million, $60 million and $51 million were outstanding at December 31, 2012, 2011 and 2010, 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.

At December 31, 2012, the benefit obligations for these plans totaled $370 million and the fair value of plan assets totaled $247 million, resulting in a net liability of $123 million recognized in our consolidated balance sheet, of which $116 million was a long-term liability. At December 31, 2011, the benefit obligations for these plans totaled $311 million and the fair value of plan assets totaled $219 million, resulting in a net liability of $92 million recognized in our consolidated balance sheet, of which $88 million was a long-term liability. See Note 2. Additional Financial Statement Information. Pension plan assets include diversified and high-quality federal money market funds, mutual funds and common collective trust funds. Net periodic benefit cost related to these plans totaled $27 million in 2012, $21 million in 2011, and $21 million in 2010. We plan to make contributions of $26 million in 2013.

Note 15. 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, and basis swaps. 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 10. Derivative Instruments and Hedging Activities.

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

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

	Fair Value Measurements Using				
	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
(millions)					
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)
December 31, 2011					
Financial Assets					
Mutual Fund Investments	$ 99	$ —	$ —	$ —	$ 99
Commodity Derivative Instruments	—	99	—	(52)	47
Financial Liabilities					
Commodity Derivative Instruments	—	(135)	—	52	(83)
Portion of Deferred Compensation Liability Measured at Fair Value	(162)	—	—	—	(162)

(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:

	Fair Value Measurements Using				
Description	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Net Book Value [2]	Total Pre-tax (Non-cash) Impairment Loss
(millions)					
Year Ended December 31, 2012					
Impaired Oil and Gas Properties	$ —	$ —	$ 228	$ 332	$ 104
Year Ended December 31, 2011					
Impaired Oil and Gas Properties	—	—	213	970	757
Year Ended December 31, 2010					
Impaired Oil and Gas Properties	—	—	30	174	144

(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 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%. 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 payments approximate fair value because they have been discounted at the prevailing market rates for similar debt instruments. As such, we consider the fair value of our CONSOL installment payments to be Level 2 measurements on the fair value hierarchy. See Note 12. Long-Term Debt. Fair value information regarding our debt is as follows:

	December 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount [1]	$ 3,797	$ 4,570	$ 4,114	$ 4,733

(1) Excludes Aseng FPSO lease obligation. No floating rate debt was outstanding at December 31, 2012 or December 31, 2011. See Note 12. Long-Term Debt.

Note 16. 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,		
	2012	2011	2010
(millions, except per share amounts)			
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$ 965	$ 412	$ 631
Weighted Average Number of Shares Outstanding, Basic	178	176	175
Incremental Shares From Assumed Conversion of Dilutive Stock Options and Restricted Stock	2	3	2
Weighted Average Number of Shares Outstanding, Diluted	180	179	177
Earnings from Continuing Operations Per Share, Basic	**$ 5.43**	**$ 2.34**	**$ 3.61**
Earnings from Continuing Operations Per Share, Diluted	**5.37**	**2.31**	**3.56**

Additional Information			
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	3	2
Weighted average option exercise price per share	$ 97.46	$ 85.40	$ 74.01

Note 17. Segment Information

We have operations throughout the world and manage our operations by country. 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); 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, 2012, our remaining North Sea assets were reclassified to assets held for sale, and prior year amounts have been reclassified to exclude the North Sea geographical segment. See Note 3. Acquisitions and Divestitures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Year Ended December 31, 2012					
Revenues from Third Parties (1)	$ 4,037	$ 2,339	$ 1,343	$ 178	$ 177
Income from Equity Method Investees	186	—	186	—	—
Total Revenues	4,223	2,339	1,529	178	177
DD&A	1,370	929	255	111	75
Asset Impairments	104	73	—	31	—
Gain on Divestitures	(154)	(154)	—	—	—
Gain on Commodity Derivative Instruments	(75)	(76)	1	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,356	806	1,074	9	(533)
Equity Method Investments	367	121	230	—	16
Additions to Long-Lived Assets	3,525	2,046	447	869	163
Goodwill at End of Year	635	635	—	—	—
Total Assets at End of Year (2)	17,509	11,199	3,063	2,572	675
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)
Gain on Commodity Derivative Instruments	(42)	(74)	32	—	—
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
Year Ended December 31, 2010					
Revenues from Third Parties (1)	$ 2,615	$ 1,893	$ 349	$ 191	$ 182
Reclassification from AOCL (3)	(20)	(20)	—	—	—
Income from Equity Method Investees	118	—	118	—	—
Total Revenues	2,713	1,873	467	191	182
DD&A	819	719	39	22	39
Asset Impairments	144	119	—	25	—
Gain on Divestitures	(113)	(113)	—	—	—
Gain on Commodity Derivative Instruments	(157)	(168)	11	—	—
Income (Loss) from Continuing Operations Before Income Taxes	848	713	355	119	(339)
Equity Method Investments	285	—	285	—	—
Additions to Long-Lived Assets	2,725	1,796	612	270	47
Goodwill at End of Year	696	696	—	—	—
Total Assets at End of Year (2)	12,846	9,091	2,270	919	566

(1) Revenues from third parties for all foreign countries, in total, were $1.7 billion in 2012, $1.1 billion in 2011, and $722 million in 2010.

(2) Long-lived assets located in all foreign countries, in total, were $4.2 billion, $3.2 billion, and $2.0 billion at December 31, 2012, 2011, and 2010 respectively.

(3) Revenues for the year ended December 31, 2010 include decreases resulting from hedging activities. The decreases resulted from hedge gains and losses that were deferred in AOCL, as a result of previous cash flow hedge accounting, and subsequently reclassified to revenues. All hedge gains and losses had been reclassified to revenues by December 31, 2010.

Note 18. 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, 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%
Year Ended December 31, 2010		
Glencore Energy UK Ltd	17%	11%

(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 Alen, offshore Equatorial Guinea, and Tamar and 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.

Note 19. Additional Shareholders' Equity Information

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

	Year Ended December 31,	
	2012	2011
Common Stock Shares Issued		
Shares, Beginning of Period	196,656,846	195,440,048
Exercise of Common Stock Options	1,265,231	837,096
Restricted Stock Awards, Net of Forfeitures	426,665	379,702
Shares, End of Period	198,348,742	196,656,846
Treasury Stock		
Shares, Beginning of Period	18,736,520	18,650,064
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	141,124	186,556
Rabbi Trust Shares Distributed and/or Sold	(102,268)	(100,100)
Shares, End of Period	18,775,376	18,736,520

Accumulated other comprehensive loss in the shareholders' equity section of the balance sheet included:

	Accumulated Other Comprehensive Loss			
	Oil and Gas Cash Flow Hedges	Interest Rate Cash Flow Hedges	Pension-Related and Other	Total
(millions)				
December 31, 2009	$ (12)	$ (2)	$ (61)	$ (75)
Realized Amounts Reclassified Into Earnings	12	1	3	16
Net Change in Other	—	(41)	(4)	(45)
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)

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

Note 20. 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, 2012 Henry Hub natural gas price strip, we forecast our CONSOL Carried Cost Obligation will be suspended throughout the 2013 fiscal year. Therefore, specific payment dates for funding cannot be determined at this time and are excluded from the minimum commitments table below. See Note 3. Acquisitions and Divestitures.

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 $37 million in 2012, $31 million in 2011, and $27 million in 2010.

Minimum commitments as of December 31, 2012 consist of the following:

	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering	Operating Lease Obligations	FPSO Lease Payments[1]	Total
(millions)					
2013	$ 739	$ 81	$ 47	$ 72	$ 939
2014	191	78	42	72	383
2015	175	86	52	70	383
2016	101	88	52	45	286
2017	—	87	48	45	180
2018 and Thereafter	—	311	302	109	722
Total	$ 1,206	$ 731	$ 543	$ 413	$ 2,893

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 12. 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, 2012, 2011, and 2010 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 Vice President - Strategic Planning, Environmental Analysis & Reserves 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, 2012. 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, Ecuador (through November 24, 2010), Falkland Islands, North Sea, Nicaragua, Sierra Leone, Senegal/Guinea-Bissau 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 extract 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).

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, 2009	209	92	35	336
Revisions of Previous Estimates [3]	15	1	(5)	11
Extensions, Discoveries and Other Additions [4]	25	26	3	54
Purchase of Minerals in Place [5]	23	—	—	23
Sale of Minerals in Place [6]	(28)	—	—	(28)
Production [7]	(19)	(7)	(5)	(31)
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
Proved Developed Reserves as of				
December 31, 2009	122	49	23	194
December 31, 2010	119	43	21	183
December 31, 2011	134	60	13	207
December 31, 2012	130	60	8	198
Proved Undeveloped Reserves as of				
December 31, 2009	87	43	12	142
December 31, 2010	106	69	7	182
December 31, 2011	110	46	6	162
December 31, 2012	114	40	5	159

(1) United States NGL proved reserves totaled:

	United States NGL Reserves (MMBbls)		
	Proved Developed	Proved Undeveloped	Total Proved
December 31, 2009	27	16	43
December 31, 2010	38	23	61
December 31, 2011	49	24	73
December 31, 2012	42	30	72

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

(3) The 2010 US revisions include the impacts of higher prices and additional NGLs recorded in Wattenberg, partially offset by the reclassification of 16 MMBbls of PUD reserves to probable reserves, primarily in Wattenberg, as a result of the SEC's five year development rule. The 2010 revisions to other international reserves are related to performance revisions in China and the North Sea.

The 2011 US revisions were primarily associated with reclassification of vertical PUDs to probable reserves in Wattenberg which are 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 are associated with performance revisions in China and the North Sea.

The 2012 US revisions are primarily attributable to our decision to terminate the legacy vertical drilling program in Wattenberg and focus on the horizontal development of the Niobrara formation. Equatorial Guinea revisions are associated with performance revisions for the Aseng field. See Items 1. and 2. Business and Properties - Proved Undeveloped Reserves (PUDs).

(4) The 2010 increase in US proved reserves relates to continuing development of onshore assets, primarily in the DJ Basin. The 2010 increase in Equatorial Guinea reserves includes 26 MMBbl for the Alen field.

The 2011 increase is 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. See Items 1. and 2. Business and Properties - Proved Undeveloped Reserves (PUDs).

(5) The 2010 increase relates to the DJ Basin asset acquisition. See Note 3. Acquisitions and Divestitures.

(6) In 2010, we sold non-core, onshore US assets in the Mid-Continent and Illinois Basin.

In 2012 we sold non-core, onshore US and North Sea assets. See Note 3. Acquisitions and Divestitures.

(7) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2012, 2011 and 2010.

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, 2009	1,534	940	234	196	2,904
Revisions of Previous Estimates [2]	(6)	12	(41)	(3)	(38)
Extensions, Discoveries and Other Additions [3]	140	—	1,698	—	1,838
Purchase of Minerals in Place [4]	139	—	—	—	139
Sale of Minerals in Place [5]	(35)	—	—	(160)	(195)
Production	(146)	(83)	(47)	(11)	(287)
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
Proved Developed Reserves as of					
December 31, 2009	1,114	638	191	192	2,135
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
Proved Undeveloped Reserves as of					
December 31, 2009	420	302	43	4	769
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

(1) Other International includes China, Ecuador (at December 31, 2009), and the North Sea. See Note 3. Acquisitions and Divestitures and Note 4. Asset Impairments.

(2) The 2010 US revisions are a combination of increases from higher natural gas prices, which were more than offset by gas shrinkage from additional NGLs recorded in Wattenberg and the reclassification of 85 Bcf of PUDs to probable reserves, primarily in Wattenberg, as a result of the SEC's five year development rule. Equatorial Guinea's positive revision in 2010 is primarily due to additional production allowances related to LNG sales. Israel's revisions in 2010 reflected a change in the likelihood that the Noa field would be developed.

The 2011 US revisions were primarily associated with reclassification of vertical PUDs in Wattenberg which are 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 are associated with performance revisions in the North Sea.

The 2012 US revisions are primarily attributable to our decision to terminate the legacy vertical drilling program in Wattenberg 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. International revisions are due to performance revisions in the Mari B field. See Items 1. and 2. Business and Properties - Proved Undeveloped Reserves (PUDs).

(3) The 2010 increase in US proved reserves is due to continuing development of onshore assets, primarily in the DJ Basin, Piceance Basin, and East Texas. The 2010 increase in Israel is due to the recording of initial reserves at the Tamar development.

The 2011 increase in the US is 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 includes reserves for Noa which we decided to develop (See Items 1. and 2. Business and Properties - Eastern Mediterranean).

The 2012 increase in US reserves includes 305 Bcf in the DJ Basin and 291 Bcf in the Marcellus Shale. The Equatorial Guinea increase is due to additions at Aseng, and the Israel increase is due to additional appraisal activity at Tamar. See Items 1. and 2. Business and Properties - Proved Undeveloped Reserves (PUDs).

(4) The increases relate to our DJ Basin asset acquisition in 2010 and our Marcellus Shale asset acquisition in 2011. See Note 3. Acquisitions and Divestitures.

(5) In 2010, we sold non-core, onshore US assets in the Mid-Continent and Illinois Basin. Other International sales in 2010 include 160 Bcf due to the termination of the Block 3 PSC by the Ecuadorian government.

In 2012, we sold non-core, onshore US and North Sea assets. See Note 3. Acquisitions and Divestitures.

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, 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
Year Ended December 31, 2010					
Revenues					
Sales [5]	$ 1,874	$ 349	$ 191	$ 418	$ 2,832
Sales to Affiliated Power Plant	—	—	—	35	35
Total Revenues	1,874	349	191	453	2,867
Production Costs [2]	449	50	15	94	608
Exploration Expense	130	7	11	48	196
DD&A	719	39	22	82	862
Asset Impairments	119	—	25	—	144
Income before Income Taxes	457	253	118	229	1,057
Income Tax Expense	160	63	21	62	306
Results of Operations [4]	$ 297	$ 190	$ 97	$ 167	$ 751

(1) Other International includes the North Sea, Ecuador (through November 24, 2010), China, Cameroon, Cyprus, Senegal/Guinea-Bissau, Nicaragua, Falkland Islands, Sierra Leone and other new ventures. See Note 3. Acquisitions and Divestitures.

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

(3) During 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 cannot conclude it is more likely than not that some portion or all of the deferred tax assets will be realized.

(4) Results of operations exclude the mark-to-market gain or loss on certain commodity derivative instruments not designated as cash flow hedges, corporate overhead and interest costs. See Note 10. Derivative Instruments and Hedging Activities.

(5) Includes impact resulting from applying cash flow hedge accounting for related commodity derivative instruments. See Note 10. Derivative Instruments and Hedging Activities.

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

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

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

	United States	Equatorial Guinea	Israel	Other Int'l [2]	Total
(millions)					
Year Ended December 31, 2012					
Property Acquisition Costs					
Unproved [4]	$ 68	$ —	$ —	$ 28	$ 96
Exploration Costs [5]	335	56	125	173	689
Development Costs [6]	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 [3]	$ 392	$ —	$ —	$ —	$ 392
Unproved [4]	942	—	—	40	982
Total Acquisition Costs	1,334	—	—	40	1,374
Exploration Costs [5]	241	54	146	152	593
Development Costs [6]	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
Year Ended December 31, 2010					
Property Acquisition Costs					
Proved [3]	$ 352	$ —	$ —	$ —	$ 352
Unproved [4]	304	1	—	—	305
Total Acquisition Costs	656	1	—	—	657
Exploration Costs [5]	306	6	52	54	418
Development Costs [6]	964	596	236	75	1,871
Total Consolidated Operations	$ 1,926	$ 603	$ 288	$ 129	$ 2,946

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes Cameroon, China, Cyprus, Ecuador (through November 24, 2010), Falkland Islands, the North Sea, Senegal/Guinea-Bissau, Nicaragua, Sierra Leone and other new ventures. See Note 3. Acquisitions and Divestitures.

(3) Proved property acquisition costs include $386 million related to the Marcellus Shale asset acquisition in 2011 and $352 million related to the DJ Basin asset acquisition in 2010.

(4) 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 (the AGC Profond block), $31 million related to additional acreage in the DJ Basin and $58 million related to other onshore US.

2010 unproved property acquisition costs include: $146 million related to the DJ Basin asset acquisition, $38 million for deepwater Gulf of Mexico lease blocks and the remainder for other onshore US lease acquisitions primarily in Wattenberg.

(5) 2012 exploration costs include drilling and completion of $102 million in Israel, $71 million in Falkland Islands, $40 million in Equatorial Guinea, $36 million in the DJ Basin, and $13 million in Cyprus.

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.

2010 exploration costs include drilling and completion costs of $62 million in deepwater Gulf of Mexico and $41 million in Israel.

(6) Worldwide development costs include amounts spent to develop PUDs of approximately $1.8 billion in 2012, $1.4 billion in 2011 and $1.1 billion in 2010.

US development costs include increases in asset retirement obligations of $73 million in 2012, $115 million in 2011, and $15 million in 2010. Other international development costs include increases in asset retirement obligations of $72 million in 2012, $13 million in 2011, and $2 million in 2010.

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 and $266 million in 2010. These capitalized costs were included in development costs as the Aseng FPSO was constructed.

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,	
	2012	2011
(millions)		
Unproved Oil and Gas Properties [1]	$ 1,399	$ 1,519
Proved Oil and Gas Properties [2]	18,297	17,538
Total Oil and Gas Properties	19,696	19,057
Accumulated DD&A	(6,252)	(6,417)
Net Capitalized Costs [3]	$ 13,444	$ 12,640
Company's share of CONE LLC Net Capitalized Costs	$ 118	$ 65

(1) Unproved oil and gas properties includes $740 million, of which $734 million is related to Marcellus Shale, at December 31, 2012, and $874 million, of which $792 million is related to Marcellus Shale, at December 31, 2011, remaining from the allocation of costs to unproved properties acquired in previous acquisitions.

(2) Proved oil and gas properties include asset retirement costs of $334 million and $310 million at December 31, 2012 and 2011, respectively.

(3) Includes $200 million of proved oil and gas properties and $160 million of accumulated DD&A related to the North Sea classified as assets held for sale at December 31, 2012. See Note 3. Acquisitions and Divestitures.

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

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited) The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows in accordance with US GAAP for extractive activities. 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, 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
December 31, 2010					
Future Cash Inflows [2]	$ 22,078	$ 8,373	$ 7,983	$ 2,083	$ 40,517
Future Production Costs [3]	6,140	1,598	460	664	8,862
Future Development Costs	4,099	1,154	924	240	6,417
Future Income Tax Expense	3,863	1,299	1,366	517	7,045
Future Net Cash Flows	7,976	4,322	5,233	662	18,193
10% Annual Discount for Estimated Timing of Cash Flows	3,941	1,589	3,530	127	9,187
Standardized Measure of Discounted Future Net Cash Flows	$ 4,035	$ 2,733	$ 1,703	$ 535	$ 9,006

(1) Other International includes China and the North Sea. See Note 3. Acquisitions and Divestitures.

(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, 2012					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 74.64	$ 100.97	$ 105.38	$ 114.54	$ 83.39
Average Natural Gas Price per Mcf	2.66	0.25	6.36	6.77	3.99
December 31, 2011					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 78.90	$ 103.01	$ 99.92	$ 111.50	$ 87.38
Average Natural Gas Price per Mcf	4.24	0.25	5.85	6.55	4.35
December 31, 2010					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 65.63	$ 72.93	$ 79.35	$ 77.41	$ 68.79
Average Natural Gas Price per Mcf	4.49	0.25	4.22	3.76	3.53

(1) Other International includes China and the North Sea. See Note 3. Acquisitions and Divestitures.

We estimate that a $1.00 per Bbl change in the average price of crude oil from the 12-month average price for 2012 would change the discounted future net cash flows before income taxes by approximately $216 million. We estimate that a $0.10 per Mcf change in the average price of natural gas from the 12-month average price for 2012 would change the discounted future net cash flows before income taxes by approximately $229 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 $1.8 billion in 2013, $1.5 billion in 2014 and $1.1 billion in 2015.

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,		
	2012	2011	2010
(millions)			
Imbalance Receivables	$ 29	$ 28	$ 25
Imbalance Liabilities	25	22	18

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,		
	2012	2011	2010
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$ 13,289	$ 9,006	$ 4,932
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(3,463)	(2,864)	(2,251)
Net Changes in Prices and Production Costs	(1,902)	4,926	3,115
Extensions, Discoveries and Improved Recovery, Less Related Costs	1,811	2,039	2,820
Changes in Estimated Future Development Costs	1,042	(710)	(915)
Development Costs Incurred During the Period	2,988	2,529	1,869
Revisions of Previous Quantity Estimates	(1,256)	(1,320)	33
Purchases of Minerals in Place	—	115	646
Sales of Minerals in Place	(1,141)	(6)	(652)
Accretion of Discount	1,860	1,278	722
Net Change in Income Taxes	732	(1,540)	(1,487)
Change in Timing of Estimated Future Production and Other	(879)	(164)	174
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	(208)	4,283	4,074
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$ 13,081	$ 13,289	$ 9,006

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)					
2012 [1]					
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 Per Share [3]					
Income from Continuing Operations	$ 1.40	$ 1.55	$ 0.92	$ 1.56	$ 5.43
Discontinued Operations, Net of Tax	0.08	0.09	0.32	(0.15)	0.34
Net Income	1.48	1.64	1.24	1.41	5.77
Diluted Earnings Per Share [3] [4]					
Income from Continuing Operations	$ 1.39	$ 1.49	$ 0.91	$ 1.54	$ 5.37
Discontinued Operations, Net of Tax	0.08	0.09	0.32	(0.15)	0.34
Net Income	1.47	1.58	1.23	1.39	5.71
2011 [2]					
Revenues	$ 786	$ 842	$ 879	$ 897	$ 3,404
Income (Loss) from Continuing Operations Before Income Taxes	(31)	356	699	(522)	502
Income (Loss) from Continuing Operations	(34)	269	491	(314)	412
Discontinued Operations, Net of Tax	48	25	(50)	18	41
Net Income (Loss)	14	294	441	(296)	453
Basic Earnings (Loss) Per Share [3]					
Income from Continuing Operations	$ (0.20)	$ 1.51	$ 2.78	$ (1.77)	$ 2.34
Discontinued Operations, Net of Tax	0.28	0.15	(0.28)	0.10	0.23
Net Income (Loss)	0.08	1.66	2.50	(1.67)	2.57
Diluted Earnings (Loss) Per Share [3] [4]					
Income from Continuing Operations	$ (0.20)	$ 1.47	$ 2.67	$ (1.77)	$ 2.31
Discontinued Operations, Net of Tax	0.28	0.14	(0.28)	0.10	0.23
Net Income (Loss)	0.08	1.61	2.39	(1.67)	2.54

(1) First quarter 2012 included the following:

- $96 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $73 million (See Note 10. 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 10. Derivative Instruments and Hedging Activities); and
- $9 million pre-tax gain on sale of non-core onshore US assets (See Note 3. Acquisitions and Divestitures).

Third quarter 2012 included the following:

- $135 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $131 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $157 million pre-tax gain on sale of non-core onshore US assets (See Note 3. Acquisitions and Divestitures).

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 asset, due to post closing adjustments (See Note 3. Acquisitions and Divestitures); and
- $30 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $36 million (See Note 10. Derivative Instruments and Hedging Activities).

(2) First quarter 2011 included the following:
- $8 million impairment charges (See Note 4. Asset Impairments); and
- $286 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $303 million (See Note 10. Derivative Instruments and Hedging Activities).

Second quarter 2011 included the following:
- $131 million impairment charges (See Note 4. Asset Impairments);
- $143 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $142 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $25 million pre-tax gain on divestitures due to the completed transfer of assets and exit from Ecuador (See Note 3. Acquisitions and Divestitures).

Third quarter 2011 included the following:
- $322 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $300 million (See Note 10. Derivative Instruments and Hedging Activities).

Fourth quarter 2011 included the following:
- $620 million asset impairment charges (See Note 4. Asset Impairments); and
- $137 million loss on commodity derivative instruments, including unrealized mark-to-market gain of $44 million (See Note 10. 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 calculations for the three months ended June 30, 2012 excludes a deferred compensation gain of $7 million, net of tax, and for the three months ended June 30 and September 30, 2011 exclude deferred compensation gains of $4 million and $12 million, respectively, 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, 2012. 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 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

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 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

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

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

SIGNATURES

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

NOBLE ENERGY, INC.
(Registrant)

Date: February 7, 2013	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, Chief Executive Officer and Director
Date: February 7, 2013	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Senior Vice President, Chief Financial Officer
Date: February 7, 2013	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 7, 2013
/s/ Kenneth M. Fisher Kenneth M. Fisher	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 7, 2013
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 7, 2013
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 7, 2013
/s/ Michael A. Cawley Michael A. Cawley	Director	February 7, 2013
/s/ Edward F. Cox Edward F. Cox	Director	February 7, 2013
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 7, 2013
/s/ Eric P. Grubman Eric P. Grubman	Director	February 7, 2013
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 7, 2013
/s/ Scott D. Urban Scott D. Urban	Director	February 7, 2013
/s/ William T. Van Kleef William T. Van Kleef	Director	February 7, 2013

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 May 25, 2012, of the Registrant (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, and incorporated herein by reference).
3.2	—	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 19, 2009 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	—	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).
4.6	—	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).
4.7	—	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).
4.8	—	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).
4.9	—	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).
4.10	—	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).
4.11	—	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).

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*	—	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).
10.3*	—	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).
10.4*	—	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).
10.5*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.6*	—	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).
10.7	—	$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).
10.8*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009, (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
10.9*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.10*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.11*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (effective September 1, 2008) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 and incorporated herein by reference).
10.12*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. dated effective March 17, 2011 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: March 17, 2011) filed March 22, 2011 and incorporated herein by reference).
10.13*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 27, 2009) filed on February 2, 2009 and incorporated herein by reference).
10.14*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, (filed as Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference).
10.15*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 26, 2011), (filed as exhibit 10.1 to Registrant's Current Report on Form 8-K (Date of Event: April 26, 2011) filed April 27, 2011 and incorporated herein by reference).
10.16*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (as amended effective January 1, 2008), (filed as Exhibit 10.40 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.17*	—	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).
10.18*	—	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).

Exhibit Number		Exhibit **
10.19*	—	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).
10.20	—	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).
10.21	—	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).
10.22	—	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).
10.23	—	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).
10.24*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, filed herewith.
10.25*	—	Form of Restricted Stock Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, filed herewith.
10.26*	—	Form of Restricted Stock Agreement (for inducement awards) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, filed herewith.
10.27*	—	Form of Restricted Stock Agreement (performance-vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, filed herewith.
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
14.1	—	Noble Energy, Inc. Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011 and incorporated herein by reference).
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 Senior Vice President and Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

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