NOBLE ENERGY INC
Form 10-K
February 09, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission file number: 001-07964
NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	73-0785597
(State of incorporation)	(I.R.S. employer identification number)
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, $3.33-1/3 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. x Yes o No

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

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

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

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

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2011: $15.6 billion.
Number of shares of Common Stock outstanding as of January 13, 2012: 176,958,537.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2012 Annual Meeting of Stockholders to be held on April 24, 2012, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2011, are incorporated by reference into Part III.

TABLE OF CONTENTS

Table of Contents

GLOSSARY

In this report, the following abbreviations are used:

Bbl	Barrel
BBoe	Billion barrels oil equivalent
Bcf	Billion cubic feet
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
HH	Henry Hub Index
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbl/d	Thousand barrels per day
MBbls	Thousand barrels
MBoe	Thousand barrels oil equivalent
MBoe/d	Thousand barrels oil equivalent per day
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MMBbls	Million barrels
MMBoe	Million barrels oil equivalent
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMcfe	Million cubic feet equivalent
MMcfe/d	Million cubic feet equivalent per day
MMgal	Million gallons
NGL	Natural gas liquids
PSC	Production sharing contract
Tcfe	Trillion cubic feet equivalent
US GAAP	United States generally accepted accounting principles
WTI	West Texas Intermediate Index

Table of Contents

PART I

Items 1. and 2. Business and Properties

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

General

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide oil and gas exploration and production. Noble Energy is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange (NYSE) since 1980. 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.

Our aim is to achieve growth in value and cash flow through exploration success and the development of a high-quality, diversified 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, such as our entry into a new core area in 2011, the Marcellus Shale, and the Denver-Julesberg (DJ) Basin asset acquisition in 2010, combined with the periodic divestment of non-core assets, have allowed us to achieve our objective of a well-balanced and diversified asset portfolio.

Our portfolio is balanced between short-term and long-term projects, both onshore and offshore. The first of our major development projects, Aseng, offshore Equatorial Guinea, began commercial crude oil production in November 2011, coming online earlier than scheduled and 13% under budget. Onshore US assets provide a stable base of production and accommodate flexible capital spending programs that are responsive to ongoing changes in the economic environment. Our long-term development projects, while requiring multi-year capital investment, are expected to offer attractive financial returns and 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 areas provide:

- most 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 sufficient liquidity levels. See Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2007-2011.

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 flow through the various development phases including appraisal drilling, front-end engineering and design, infrastructure build-out and exploitation. We currently have projects spanning all phases of the development cycle with some contributing production in 2011 and others with first production targets ranging from 2012 through 2016 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);
- Galapagos (deepwater Gulf of Mexico);
- Tamar (offshore Israel);
- Aseng (offshore Equatorial Guinea); and
- Alen (offshore Equatorial Guinea).

Unsanctioned Projects

- Gunflint (deepwater Gulf of Mexico);
- Leviathan (offshore Israel);
- Diega (offshore Equatorial Guinea); and
- West Africa gas project (offshore Equatorial Guinea).

Additionally, in December 2011, we announced our natural gas discovery well (A-1) in Block 12, offshore Cyprus.

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.

Table of Contents

Proved Oil and Gas Reserves Proved reserves estimates at December 31, 2011 were as follows:

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

	December 31, 2011 Proved Reserves		
Reserves Category	Crude Oil, Condensate & NGLs (MMBbls)	Natural Gas (Bcf)	Total (1) (MMBoe)
Proved Developed			
United States	134	1,195	333
Equatorial Guinea	60	497	143
Israel	-	83	14
Other International (2)	13	11	14
Total Proved Developed Reserves	207	1,786	504
Proved Undeveloped			
United States	110	781	240
Equatorial Guinea	46	289	94
Israel	3	2,186	368
Other International (2)	3	1	3
Total Proved Undeveloped Reserves	162	3,257	705
Total Proved Reserves	369	5,043	1,209

(1) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.

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

Estimated reserves at the end of 2011 were approximately 1.2 BBoe, an 11% increase from 2010. US reserves accounted for 47% of the total, and international reserves accounted for 53%. Our 2011 reserves mix is 31% global liquids, 42% international natural gas, and 27% 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 a significant portfolio of major development projects. We have numerous exploration opportunities remaining in these areas and are also engaged in new venture activity in the US and international locations.

Appraisal, Development and Exploitation Activities   Our exploration success and strategic acquisitions have provided us with numerous development opportunities, as demonstrated in our growing inventory of major development projects. In 2011, we commenced oil production from Aseng, the first of our major development projects, seven months ahead of the original schedule and 13% under budget. 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.

Table of Contents

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 rebalances 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 close to the US's largest gas market, the Northeast US. It significantly increases our inventory of low risk, repeatable 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 balance to our rapidly expanding international programs.

Under the terms of the CONSOL agreement, we acquired 50% interests in approximately 628,000 net undeveloped acres, existing Marcellus Shale production and existing infrastructure for approximately $1.3 billion, including post-closing adjustments. Payments will be made in three annual installments, with the first installment made at closing on September 30, 2011. We will pay an additional $2.1 billion in the form of a carry of CONSOL's drilling and completion costs. The carry, which we expect to extend over approximately eight years or more, is capped at $400 million annually and suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices. Initially, we will be the designated operator of the wet-gas areas (areas with more condensate or liquids) and CONSOL will be the designated operator of the dry-gas areas (areas with little or no condensate or liquids).

As a result of this transaction, we are now focusing on three core areas within the US: the DJ Basin, the Marcellus Shale, and the deepwater Gulf of Mexico. We are also considering the divestiture of certain non-core onshore US properties from our portfolio.

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 and Note 12. Long-Term Debt.

Exit from Ecuador In May 2011, we transferred our assets in Ecuador to the Ecuadorian government. The Ecuadorian government had previously terminated our Block 3 PSC (100% working interest) on November 23, 2010, as we had not negotiated a service contract on Block 3 in accordance with the terms of a newly-enacted hydrocarbon law. The law aimed to change existing production sharing arrangements into service contracts and provided for renegotiation of certain contracts by November 23, 2010. 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.

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. 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, and provides significant growth potential. Included in the purchase were approximately 323,000 total net acres.

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.

Asset Impairments During 2011, we recorded impairment charges of $759 million mainly related to our non-core onshore US assets. The majority of these impairment charges were triggered by the significant decline, approximately 17% over a five year future period, in natural gas prices in the fourth quarter of 2011. The US natural gas price environment continued to be volatile during 2011 as spot prices declined 32% from $4.41 per MMBtu at December 31, 2010 to $2.99 MMBtu at December 31, 2011. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Table of Contents

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 54% of our 2011 total consolidated sales volumes and 47% of total proved reserves at December 31, 2011. Approximately 57% of the proved reserves are natural gas and 43% are crude oil, condensate and NGLs.

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

	Year Ended December 31, 2011 Sales Volumes				December 31, 2011 Proved Reserves		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d)	Crude Oil, Condensate & NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Wattenberg	23	166	11	62	191	871	337
Marcellus Shale	-	19	-	3	-	542	90
Rocky Mountain/Mid-Continent	3	149	2	30	22	464	99
Deepwater Gulf of Mexico	10	20	1	15	21	24	25
Gulf Coast and Other	2	34	1	7	10	75	22
Total	38	388	15	117	244	1,976	573

Wells drilled in 2011 and productive wells at December 31, 2011 for our US operating areas were as follows:

	Year Ended December 31, 2011 Gross Wells Drilled or Participated in	December 31, 2011 Gross Productive Wells
Wattenberg	663	8,415
Marcellus Shale	23	102
Rocky Mountain/Mid-Continent	157	5,120
Deepwater Gulf of Mexico	1	7
Gulf Coast and Other	11	490
Total	855	14,134

Locations of our onshore US operations as of December 31, 2011 are shown on the map below:

DJ Basin / Wattenberg   One of our core operating areas is the DJ Basin, where we have a significant acreage position of over 860,000 net acres. Included in the DJ Basin is Wattenberg (approximately 96% operated working interest), our largest onshore US asset, where we have a multi-year project inventory. In 2011, we continued to improve our operational performance while accelerating our drilling activities. During 2011 we had record sales volumes from our horizontal drilling program that began in 2010 and targets the Niobrara formation.

Table of Contents

Wattenberg includes:

- our historical Wattenberg development area, where we have conducted substantial vertical development over the last several years as well as successful horizontal drilling in this high density area;
- the northern and eastern edges of our historical Wattenberg development area where we are focusing on expanding the economic limits of the field, as expansion of this area has resulted in increases in our crude oil and NGL production volumes and most of our recent horizontal drilling has been in this area; and
- northern Colorado from the edge of our historical Wattenberg development area to the Wyoming border where we began drilling horizontal wells in 2010.

During 2011, we drilled a total of 639 successful development wells in historical Wattenberg, of which, 64 were drilled horizontally into the Niobrara formation. In 2011, we began constructing multi-well horizontal drilling pads and centralized production facilities to minimize our surface use and allow for more efficient execution and operations. We are currently evaluating the viability of 80-acre horizontal well spacing and extended reach horizontal lateral wells.

Wattenberg contributed 62 MBoe/d of sales volumes and represented approximately 29% of total consolidated sales volumes in 2011, with approximately 55% being liquids, and approximately 337 MMBoe or 28% of total proved reserves at December 31, 2011. Horizontal drilling in the Niobrara has significantly expanded the economic limits of this field. Of the net sales volumes from Wattenberg, approximately 8 MBoe/d came from a total of 85 producing wells in our horizontal Niobrara program. We also drilled eight horizontal wells in the Niobrara formation in northern Colorado.

Our 2011 Wattenberg drilling program resulted in additions to proved reserves of approximately 67 MMBoe, approximately 63% of which are liquids.

We have also started a horizontal drilling program on additional acreage in southeastern Wyoming and we are evaluating processing and transportation infrastructure needs as well as optimum well completion techniques.

At year-end, we were running eight vertical rigs, five horizontal rigs and 21 completion units in the DJ Basin. We expect to add three to four horizontal rigs and drill approximately 170 horizontal operated and 280 vertical operated wells in the DJ Basin in 2012. Within the next two years, we intend to double our annualized horizontal rig count and well completions.

Marcellus Shale In September of 2011, we entered into a new core operating area, the Marcellus Shale, through a joint venture with CONSOL. During the fourth quarter of 2011, the Marcellus Shale was producing approximately 74 MMcf/d, net to us, compared to net production of 50 MMcf/d at the end of the third quarter of 2011. This represents significant growth at a pace that is faster than we had originally modeled in our acquisition economics. At December 31, 2011, net proved gas reserves were approximately 542 Bcf.

At year-end CONSOL was operating five horizontal rigs and one completion unit on our joint acreage in the Marcellus Shale. In January 2012 we began operating our first horizontal rig in conjunction with the opening of our new field office in Canonsburg, Pennsylvania. CONSOL’s expertise in permitting, local water sourcing, transportation and processing will help facilitate our growth in operations. During the remainder of 2012, we expect to add approximately two horizontal rigs in the wet-gas area of the Marcellus Shale which complements our previous experience in the liquids-rich development in the DJ Basin. We have executed a multi-year development plan with CONSOL that steadily increases the rig count through 2016, and we estimate during 2012 the joint venture will operate six horizontal rigs.

Our joint development plan for 2012 projects that CONSOL will drill approximately 60 horizontal wells in the dry-gas areas of the Marcellus Shale and that we will drill approximately 39 horizontal wells focused in the wet-gas areas of the Marcellus Shale. Our dry-gas program delivers economically attractive returns even in low natural gas price environments due to strong production performance, competitive costs, and access to the US's largest gas market, the Northeast US.

Since the joint venture agreement was finalized on September 30, 2011, CONSOL has drilled a total of 23 successful development wells on our joint acreage. All of these wells were drilled horizontally. The significant portion of acreage that is currently held by production should allow for efficient development utilizing pad drilling. Pad drilling minimizes the permit and infrastructure requirements and surface use.

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, the Marcellus Shale, and the majority of our other onshore US operating areas. Hydraulic fracturing involves the injection of a mixture, comprised of water, sand and a small amount of chemicals, under pressure into rock formations 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 219 MMBoe at December 31, 2011, will require the use of hydraulic fracturing to produce commercial quantities of crude oil and natural gas. See Hydraulic Fracturing, below, for more discussion.

Table of Contents

Other Onshore Properties We operate in the following additional onshore US areas: Rocky Mountains including Piceance Basin (Western Colorado), Iron Horse in the Wind River Basin (Central Wyoming), 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); Mid-Continent including the Shattuck field (Western Oklahoma), Granite Wash field (Texas Panhandle), and East Mid-Continent (Central Kansas); and Gulf Coast including the Haynesville field (East Texas and North Louisiana) and other properties in Texas and Louisiana. Other onshore properties accounted for 17% of total consolidated sales volumes in 2011 and 8% of total proved reserves at December 31, 2011. Although our future development focus is concentrated on our five core areas, we continue to produce and develop in these other areas. We drilled 168 development wells during 2011 and plan to drill approximately ten development wells during 2012 in these areas. Additionally, we continue to evaluate the divestment opportunities associated with certain non-core properties.

Deepwater Gulf of Mexico Locations of our deepwater Gulf of Mexico developments as of December 31, 2011 are shown on the map below:

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 four producing fields, multiple ongoing development projects and a substantial inventory of exploration opportunities.

The deepwater Gulf of Mexico accounted for 7% of total consolidated sales volumes in 2011 and 2% of total proved reserves at December 31, 2011. We currently hold leases on 102 deepwater Gulf of Mexico blocks, representing approximately 561,000 gross acres (403,000 net acres). Of our total gross acres, approximately 63,000 gross acres (33,000 net acres) have been developed. We are the operator on approximately 79% of the leases.

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 38 identified prospects, of which 23 are stand-alone, subsalt Miocene targets. The prospects are a combination of both large stand-alone prospects as well as a number of smaller, tie-back opportunities. Prospects in inventory are subject to an ongoing rigorous technical maturation process and may or may not emerge as drillable options. To support the future appraisal work in our exploration inventory, we have contracted an additional drilling rig on a shared basis in 2012 and 2013. We will have two separate four-month slots with the ENSCO 8505, which will share the Gulf of Mexico workload with our currently contracted drilling rig, the ENSCO 8501. Utilizing these drilling rigs, during 2012, we plan to drill approximately four wells, up to two of which we currently anticipate to be at our Gunflint discovery.

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for BP Exploration & Production Inc., sank after a blowout and fire (Deepwater Horizon Incident). The resulting leak caused a significant oil spill. In May 2010, due to the Deepwater Horizon Incident, the Secretary of the Interior ceased issuing offshore drilling permits pursuant to a series of moratoria and all deepwater drilling activities in progress were suspended (Deepwater Moratorium). When the Deepwater Moratorium was announced, we were required to suspend drilling operations at Deep Blue and Santiago. In April 2011, we announced that we had received the first post-moratorium blowout preventer certification, completion permit and drilling permit to resume drilling at our Santiago exploration well. We also announced in December 2011 that we received a drilling permit to commence appraisal drilling at Gunflint.

Table of Contents

Deep Blue During 2011 we resumed drilling efforts at Deep Blue (Green Canyon Block 723; 33.75% operated working interest), which was initially spud in 2009 and suspended due to the Deepwater Moratorium. In November 2011, we announced that we had finished the well and found additional hydrocarbons in high quality reservoirs. During first quarter of 2012, we will be completing additional analysis of the data from the side track well.

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. In 2009, we approved a phased development plan of the existing discoveries which includes completion of the wells and connection to the nearby Nakika production platform via subsea tieback. In May 2011, after receiving a permit to resume drilling, we announced that we had discovered commercial quantities of crude oil at Santiago, our third discovery at the Galapagos Development project. During the second quarter of 2011, we finished completion activities at Santiago. Installation of topside equipment at the host facility, and subsea tiebacks for Santa Cruz, Isabella, and Santiago are progressing. We currently expect production to commence in the second quarter of 2012.

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. Work to tie South Raton back to a non-operated host facility at Viosca Knoll Block 900 is ongoing with initial production scheduled for first quarter 2012.

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. During 2011, a unitization agreement covering the Gunflint discovery was finalized. The agreement named us as the operator and added the northern half of Mississippi Canyon blocks 992 and 993 to the project area which already included blocks 904, 948, and 949. Also as part of the agreement, our working interest was revised to 26%. Our plans to drill two or three appraisal wells during 2011 were delayed by impacts of the Deepwater Moratorium. In October 2011, we received a drilling permit and in December 2011 we resumed drilling at Gunflint. Appraisal of Gunflint is necessary to narrow the resource range before final planning and sanctioning of a development project. We currently anticipate drilling up to three appraisal wells to fully evaluate the extent of the reservoir.

We are reviewing host platform options including subsea tieback to an existing third-party host and construction of a new facility. We are currently targeting 2016 for production start-up. If we choose to connect to an existing third-party host, the project could have an accelerated completion schedule.

Swordfish (Viosca Knoll Blocks 917, 961 and 962; 85% operated working interest) Swordfish was a 2001 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 balance and 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 a number of other locations that provide further exploration opportunities.

International operations accounted for 46% of total consolidated sales volumes in 2011 and 53% of total proved reserves at December 31, 2011. International proved reserves are approximately 80% natural gas and 20% crude oil and condensate. Operations in Equatorial Guinea, Cyprus, China and Senegal/Guinea-Bissau are conducted in accordance with the terms of PSCs. In Cameroon, we operate in accordance with the terms of a PSC and a mining concession. Operations in Israel, the North Sea, and other foreign locations are conducted in accordance with concession agreements, permits or licenses.

Table of Contents

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, 2011 Sales Volumes				December 31, 2011 Proved Reserves		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d)	Crude Oil, Condensate & NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
International							
Equatorial Guinea	14	245	-	56	106	786	237
Israel	-	173	-	29	3	2,269	382
North Sea	8	5	-	9	9	11	10
China	4	-	-	4	7	1	7
Total International	26	423	-	98	125	3,067	636
Equity Investee	2	-	5	7	-	-	-
Total	28	423	5	105	125	3,067	636
Equity Investee Share of Methanol Sales (MMgal)				155			

10

Table of Contents

Wells drilled in 2011 and productive wells at December 31, 2011 in our international operating areas were as follows:

	Year Ended December 31, 2011 Gross Wells Drilled or Participated in	December 31, 2011 Gross Productive Wells
International		
Equatorial Guinea	2	18
Cameroon	1	-
Senegal/Guinea-Bissau	1	-
Israel	2	3
Cyprus	1	-
North Sea	-	27
China	5	25
Total International	12	73

West Africa (Equatorial Guinea, Cameroon and Senegal/Guinea-Bissau) West Africa is one of our core operating areas and includes the Alba field, Block O and Block I offshore Equatorial Guinea, the YoYo mining concession and Tilapia PSC offshore Cameroon, as well as the AGC Profond Block offshore Senegal/Guinea-Bissau. Equatorial Guinea accounted for approximately 26% of 2011 total consolidated sales volumes and 20% of total proved reserves at December 31, 2011. At December 31, 2011, we held approximately 119,000 net developed acres and 137,000 net undeveloped acres in Equatorial Guinea, 563,000 net undeveloped acres in Cameroon, and 729,000 net undeveloped acres in Senegal/Guinea-Bissau.

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

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.

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 under the equity method. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest, also accounted for under the equity method. 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.

Table of Contents

Significant development planning has occurred for an Alba field compression project, which is a natural progression for the operations of the field. We are evaluating certain features of project implementation and expect to grant final project approval in 2012.

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.

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 take on board stabilized condensate from gas condensate fields in the area. It is capable of processing 120 MBbl/d of liquids, including 80 MBbl/d of oil, and reinjecting 160 MMcf/d of natural gas. Storage is approximately 1.6 MMBbls of liquids.

During 2011, we concluded construction of the Aseng FPSO, which arrived on location in Equatorial Guinea and completed field installation in late 2011. We have executed an oil sale, purchase, and marketing agreement with Glencore Energy UK Ltd. for our share of Aseng production.

First production at Aseng commenced on November 6, 2011 and we completed three liftings totaling over 860 MBbl net in 2011. As of December 31, 2011, we had net oil production of approximately 19 MBbl/d.

Alen Project Alen, located primarily on Block O (45% operated working interest) offshore Equatorial Guinea, is our next West Africa 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 where it will be held until sold. 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.

During 2011, we began platform fabrication and commenced development drilling. First production at Alen is currently expected to commence by the fourth quarter of 2013 at 20 MBbl/d, net. Natural gas reinjection is estimated to be 390 MMcf/d during gas-recycling. The total gross development cost is estimated at $1.6 billion.

Other Block O & I Projects During the second quarter of 2011, we drilled the successful Diega appraisal well which encountered both crude oil and natural gas. We have drilled two sidetracks, each of which encountered hydrocarbons. We are currently finalizing our appraisal of Diega and are evaluating regional development scenarios. Additionally, in late 2011, we drilled the Carla well, a successful oil appraisal well in Block O, offshore Equatorial Guinea. We are evaluating drilling results from our Diega and Carla discovery wells, and reviewing development options and formulating a development plan for these areas.

West Africa Gas Project The Equatorial Guinea Ministry of Mines, Industry and Energy (MMIE) is considering the development of an integrated gas project (Integrated Project) which includes upstream gas projects, the required gas transportation system, and a second LNG train. Noble Energy, as Chair of the Integrated Project committee, is working with the MMIE and other Integrated Project stakeholders to determine the Integrated Project scope and schedule.

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 2011, the 3-D seismic data acquired in 2003 and 2010 over the YoYo and Tilapia blocks was reprocessed for further interpretation. Additionally, during 2011 we drilled an exploration well testing the Bwabe prospect in the Tilapia Block, offshore Cameroon, reached total depth during late 2011 and did not find commercial quantities of hydrocarbons. We are currently evaluating several prospects as a follow-up for our offshore Cameroon exploration program.

Senegal/Guinea-Bissau   During 2011, we farmed into the AGC Profond block (30% non-operated working interest), which covers more than two million gross acres and includes a number of identified prospects. The joint venture drilled the Kora-1 exploration well during 2011. The well did not result in commercial quantities of hydrocarbons; however, there are a number of prospects in the area. We are working with our partners on future exploration plans and have the option to become the operator going forward.

Eastern Mediterranean (Israel and Cyprus)   Another core operating area is located in the Eastern Mediterranean. Israel accounted for 14% of 2011 total consolidated sales volumes and 31% of total proved reserves at December 31, 2011. At December 31, 2011, we held approximately 80,000 net developed acres and 652,000 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 15 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:

Mari-B Field   The Mari-B field (47% operated working interest) was the first offshore natural gas production facility in Israel. Natural gas is delivered to a permanent onshore receiving terminal at Ashdod for distribution to purchasers. Natural gas sales began in 2004 and have increased steadily as Israel's natural gas infrastructure has developed. Our share of sales volumes rose from 48 MMcf/d in 2004 to 173 MMcf/d in 2011. In total, we have delivered over 319 Bcf of natural gas, net, to Israeli customers through December 31, 2011.

During 2011, due to multiple interruptions in imported gas supplies from Egypt, Mari-B natural gas volumes delivered at very high rates to support Israel's growing gas and power demands. As a result, we experienced accelerated depletion of the Mari-B field. In January 2012, we announced a cut back in production at Mari-B to prudently manage the reservoir and preserve its deliverability for the peak demand months during the summer of 2012.

We are currently working closely with our Israeli customers to manage demand and operating the field so that it will produce until production commences at the Tamar field, which we expect to occur during the second quarter of 2013. At that time, we plan to transition the Mari-B reservoir to a natural gas storage facility. As a result of the accelerated depletion resulting from the high demand experienced as a result of Egyptian supply interruptions, we do not believe that the Mari-B field, alone, will be able to produce enough volumes to meet anticipated Israeli demand until production begins at Tamar. We are in the process of developing the Noa project and studying potential development of the Pinnacles project, both discussed below, to support near-term deliverability into the Israeli market. See also Delivery Commitments, below.

The Mari-B facility was designed to accommodate a certain amount of reservoir subsidence as the field depleted. As we near the end of the field's producing life, the rate of subsidence could change, thereby increasing the risk of mechanical failure of individual wells and potentially decreasing the deliverability of the Mari-B field. See Item 1A. Risk Factors   Exploration, development and production risks and natural disasters could result in liability exposure or the loss of production and revenues.

Noa Project   We are in the process of developing the Noa reserves (47% operated working interest) to support near-term deliverability to Israeli customers. The Noa project allows us to continue producing through the Mari-B platform at high rates, bringing another source of natural gas through our existing Mari-B facilities before Tamar begins producing. Two development wells have been drilled, engineering and design have been completed, and installation and fabrication are progressing on schedule. First production at Noa is expected in the third quarter of 2012.

Pinnacles Project   We are also studying the potential development of Pinnacles, located near the Mari-B field, to help meet the Israeli natural gas demands. If partner approval is obtained and development occurs as expected, Pinnacles will begin producing in the third quarter of 2012.

Table of Contents

Tamar 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. In 2010, we sanctioned the development plan for Tamar and submitted the plan to the Israeli government for approval.

The initial phase of Tamar development will include five subsea wells. The natural gas produced at these wells will flow to a new offshore platform to be constructed near the existing Mari-B platform. The natural gas will then be delivered to an existing pipeline that connects the Mari-B field to the Ashdod onshore terminal. The development will allow for significant expansion as the Israeli natural gas market grows. We commenced field development drilling, platform jacket and deck fabrication, pipeline installation and onshore facility expansion during 2011, with first production expected by second quarter of 2013. The total first phase development cost of Tamar is estimated at $3.0 billion ($1.1 billion net).

The Israeli natural gas market continues to grow, and the Tamar partners are in the final stages of sales contract negotiations with the Israel Electric Corporation Limited (IEC) and are in active discussions with existing and new customers to sell natural gas from the Tamar field. See International Marketing Activities and Delivery Commitments below.

We are considering the implementation of a floating LNG (FLNG) project at Tamar and have begun conducting preliminary engineering design work. The economic viability of such a large project is dependent on the ability to export natural gas to the international market. We are working with the Israeli government to obtain support for the project.

Leviathan Project In December 2010, we announced a significant natural gas discovery at the Leviathan prospect (40% operated working interest) in the Levant Basin offshore Israel. The Leviathan field is the largest discovery in our history and was the world's largest offshore natural gas discovery in 2010.

Table of Contents

In early 2011, we drilled the Leviathan-2 appraisal well, which encountered wellbore issues resulting in our abandoning the well. The incident was a covered event under our well control insurance; therefore, we expect to recover most of the costs from insurance, subject to a deductible.

We resumed the natural gas appraisal drilling program in mid-2011 with the successful Leviathan-3 appraisal well. In January 2012, we resumed drilling at the Leviathan-1 well in order to evaluate two additional intervals for the existence of crude oil. Results from these deeper tests, which have a low chance of success, are expected during the first half of 2012.

We have project and commercial teams in place and are in the process of considering our commercialization options for Leviathan. Due to the size of the field, economic viability depends on the ability to export via pipeline or LNG. Engineering design and planning work are currently underway for a potential first phase of development; however, we have not yet sanctioned a development project.

Although we will be able to incorporate our knowledge gained on the Aseng and Tamar projects to Leviathan, such a complex, costly project is 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.

Dalit Dalit (36% operated working interest) was our second 2009 natural gas discovery in the Levant Basin. We are currently working with our partners on a cost-effective development plan.

Dolphin 1 During the fourth quarter of 2011, we completed drilling the successful Dolphin 1 (39.66% operated working interest) exploration well in the Hanna license, southwest of the Tamar gas field and are evaluating results.

Cyprus During the fourth quarter of 2011, we drilled a successful natural gas exploration well (A-1) in Block 12. The well encountered approximately 310 feet of net natural gas pay in multiple high-quality Miocene sand intervals.

In 1974 the island of Cyprus was partitioned into two parts: the Republic of Cyprus with the majority of the south under its effective control, and the Turkish-controlled area in the north, which calls itself the Turkish Republic of Northern Cyprus. The United Nations recognizes the sovereignty of the Republic of Cyprus over the entire island. The Republic of Cyprus has been a member of the European Union since May 1, 2004. The Turkish government opposes the current exploratory activities being conducted by the Republic of Cyprus, claiming such activities will have a detrimental effect on reunification negotiations, and that any development projects should be deferred until the dispute over the political status of the island is resolved. While Turkey has voiced its opposition to the drilling operations, the European Union, Russia and the US have supported Cyprus' right to drill and our activities.

Other Exploration Activities

Tanin 1 During the fourth quarter of 2011, we spud the Tanin 1 (47.06% operated working interest) well in the Alon A block, offshore Israel. In February 2012, we announced a natural gas discovery at Tanin.

Seismic

Israel During 2011, we completed the 3-D seismic survey that was started in 2010 for the Ruth, Ratio, and Alon licenses, offshore Israel.

Cyprus During 2011, we acquired approximately 1,544 square miles of 2-D seismic per our PSC work program.

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

North Sea   We have been conducting business in the North Sea (the Netherlands and the United Kingdom (UK)) since 1996 and currently have interests in 14 licenses on 15 blocks with working interests ranging from 7% to 40%. We are the operator of one block.

Most of our production is from the Dumbarton and Lochranza fields (30% non-operated working interest) in blocks 15/20a and 15/20b in the UK sector of the North Sea. We also have production from the MacCulloch, Hanze, Cook and other fields.

The Dumbarton development, which began production in 2007, includes a subsea tie-back to the GP III, an FPSO (GP III FPSO) in which we own a 30% interest. Dumbarton has eight horizontal producing wells and two water injection wells. Two additional producing wells from the nearby Lochranza discovery are tied back to the Dumbarton facilities. During 2011, we began drilling a third Lochranza well and expect production to the Dumbarton facilities in early 2012.

We also participate in the Selkirk (30.5% non-operated working interest) project, located in the UK sector of the North Sea. We are currently working with our partners on development options.

Table of Contents

The North Sea accounted for 4% of 2011 total consolidated sales volumes and 1% of total proved reserves at December 31, 2011. At December 31, 2011, we held approximately 6,360 net developed acres and 29,130 net undeveloped acres. At December 31, 2011, we were running one horizontal rig and expect to drill one horizontal development well during 2012 at our Lochranza field.

China   We have been engaged in exploration and development activities in China since 1996 under the terms of a 30-year PSC. 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. During 2011, we completed the commissioning of the newly installed B platform and commenced engineering and design of a third platform (C platform). In addition, we drilled and completed six development wells, five of which were production wells and one water injection well. The drilling results in 2011 gave us additional confidence going forward on the western side of the block.

China accounted for 2% of 2011 total consolidated sales volumes and 1% of total proved reserves at December 31, 2011. At December 31, 2011, we held approximately 4,000 net developed acres and no undeveloped acres.

Other International Properties   At December 31, 2011, we held undeveloped acreage offshore in other international locations including Nicaragua, India and France. During 2011, we acquired 3-D seismic for Nicaragua.

Proved Reserves Disclosures

Implementation of the Securities and Exchange Commission's (SEC) Revisions to Oil and Gas Disclosures   Effective December 31, 2009, we implemented the SEC's final rules related to the modernization of oil and gas reporting (SEC's reserves rules). Although the SEC's reserves rules allow probable and possible reserves to be disclosed separately, we have elected not to disclose probable and possible reserves in this report. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for a description of the most significant revisions to oil and gas reporting 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 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 rotating group of smaller fields, which combined represent over 80% of our 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 2011 reserves estimates.

Third-Party Reserves Audit   In each of the years 2011, 2010, and 2009, we retained NSAI to perform reserves audits of proved reserves. The reserves audit for 2011 included a detailed review of 14 of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 80% of US proved reserves and 98% of international proved reserves (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. The reserves audit for 2009 included a detailed review of 20 of our major fields and covered approximately 86% of total proved reserves.

Table of Contents

In connection with the 2011 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, 2011, 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 selection process results in the audit of each field representing more than 1% of total proved reserves. As a result, for each of the years 2009 – 2011, our ten largest fields at the current time were audited. The Aseng field was first audited in 2009, 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, 2011, on a quantity basis, the NSAI field estimates ranged from 17 MMBoe or 19% above to 14 MMBoe or 5% below as compared with our estimates on a field-by-field basis. Differences between our estimates and those of NSAI are reviewed for accuracy but are not further analyzed unless the aggregate variance is greater than 10%. Reserves differences at December 31, 2011 were, in the aggregate, approximately 18 MMBoe, or 2%.

Proved Undeveloped Reserves (PUDs)   As of December 31, 2011, our PUDs totaled 162 MMBbls of crude oil, condensate and NGLs and 3,257 Bcf of natural gas, for a total of 705 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, 2011:

- 146 MMBoe in the DJ Basin, including Wattenberg, where we are projecting reasonable levels of increased activity with projected rig counts in line with past levels of operations;
- 21 MMBoe in the deepwater Gulf of Mexico, 91% of which are related to our Galapagos project, which is expected to be producing in the second quarter of 2012;

- 68 MMBoe in the Marcellus Shale;
- 94 MMBoe in Equatorial Guinea, 73% of which are in the Alba field with the remainder in the Alen field. The Alba field PUDs represent compression reserves that will be recovered from existing wells and will be reclassified to proved developed during the next five years. The Alen field PUDs are scheduled to be reclassified to proved developed reserves beginning in 2013;
- 365 MMBoe in the Tamar field, offshore Israel. The Tamar field PUDs are scheduled to be reclassified to proved developed reserves when production begins, currently expected in second quarter 2013; and
- the above fields represent 99% of total PUDs. The remaining 1% is associated with ongoing developments within the next five years in other onshore US and international areas.

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

- recording of approximately 56 MMBoe PUDs acquired in the Marcellus Shale Joint Venture transaction;
- recording of approximately 58 MMBoe PUDs from ongoing onshore US development programs, primarily in Wattenberg and the Marcellus Shale;

17

Table of Contents

- recording of approximately 80 MMBoe PUDs from additional appraisal activity at Tamar, plus 3 MMBoe from other international areas;
- conversion of approximately 45 MMBoe PUDs into proved developed reserves;
- reclassification of approximately 28 MMBoe PUDs, primarily in Wattenberg including vertical Codell and J-Sand programs, that were not scheduled to be developed within five years due to additional shifting of activity to the horizontal Niobrara program;
- negative revisions of approximately 10 MMBoe, primarily from dry-gas fields in the onshore US due to reduced activity assumptions; and
- positive revisions of approximately 2 MMBoe in PUDs primarily due to changes in commodity prices.

Development Costs   Costs incurred to advance the development of PUDs were approximately $1.4 billion in 2011 (including $66 million non-cash costs related to an increase in our Aseng FPSO lease obligation), $1.1 billion in 2010 (including $266 million non-cash costs related to an increase in our Aseng FPSO lease obligation), and $440 million in 2009 (including $29 million non-cash costs related to an increase in our Aseng FPSO lease obligation). A significant portion of costs incurred in 2011 related to our major development projects horizontal Niobrara, Aseng, Marcellus Shale, Alen, Tamar and Galapagos, 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 $2.4 billion in 2012, $1.3 billion in 2013, and $1.0 billion in 2014. 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 PUDs drilling locations are scheduled to be drilled prior to the end of 2016. 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 2016. Initial production from these PUDs is expected to begin during the years 2012 - 2016.

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, 2011, no crude oil or natural gas reserves information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (EIA) of the US Department of Energy. We file Form 23, including reserves and other information, with the EIA.

Table of Contents

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, 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
Other	2	-	-	106.87	-	-	9.08
Mari-B Field (Israel)	-	173	-	-	4.86	-	1.16
North Sea	8	5	-	112.97	8.11	-	14.95
China	4	-	-	106.19	-	-	9.61
Total Consolidated Operations	64	811	15	100.93	3.04	48.35	5.07
Equity Investee (3)	2	-	5	108.76	-	72.71	
Total	66	811	20	$101.13	$3.04	$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
North Sea	10	6	-	80.24	5.35	-	11.53
Ecuador (5)	-	25	-	-	-	-	-
China	4	-	-	75.15	-	-	7.49
Total Consolidated Operations	64	787	14	76.46	3.00	41.21	4.93
Equity Investee (3)	2	-	5	77.98	-	53.68	
Total	66	787	19	$76.50	$3.00	$44.90	
Year Ended December 31, 2009							
United States							
Wattenberg	15	150	6	$55.57	$3.59	$29.10	$ 3.01
Other US	22	247	4	54.92	3.62	26.37	8.50
Total US (4)	37	397	10	55.19	3.61	27.96	6.26
Alba Field (Equatorial Guinea) (2)	14	239	-	55.94	0.27	-	2.30
Mari-B Field (Israel)	-	114	-	-	3.47	-	1.36
North Sea	7	5	-	59.51	5.75	-	15.81
Ecuador	-	26	-	-	-	-	-
China	4	-	-	54.40	-	-	6.75
Total Consolidated Operations	62	781	10	55.76	2.54	27.96	5.05
Equity Investee (3)	2	-	6	59.51	-	36.03	
Total	64	781	16	$55.87	$2.54	$31.20	

(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.

Average crude oil sales prices reflect a reduction of $5.57 per Bbl (2009) from hedging activities. This price reduction resulted from hedge losses that were previously deferred in accumulated other comprehensive loss (AOCL). All hedge losses relating to Equatorial Guinea production had been reclassified to revenues by December 31, 2009.

(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 (2010), and $2.13 per Bbl (2009) from hedging activities. Average natural gas sales prices reflect a decrease of $0.01 per Mcf (2010) from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis. 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.

Table of Contents

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, 2011, our operated properties accounted for approximately 67% 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, 2011 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	6,953	6,163.0	7,181	5,327.7	14,134	11,490.7
Equatorial Guinea	4	1.6	14	5.0	18	6.6
Israel	-	-	3	1.4	3	1.4
North Sea	18	4.0	9	1.0	27	5.0
China	24	13.7	1	0.6	25	14.3
Total	6,999	6,182.3	7,208	5,335.7	14,207	11,518.0

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, 2011 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore (1)	2,065	1,305	1,890	1,351
Offshore	119	57	481	363
Total United States	2,184	1,362	2,371	1,714
International				
Equatorial Guinea	285	119	307	137
Senegal/Guinea-Bissau	-	-	2,431	729
Cameroon	-	-	1,125	563
Israel	185	80	1,469	652
Cyprus (2)	-	-	852	596
North Sea (3)	36	6	147	29
China	7	4	-	-
France (4)	-	-	2,808	2,036
Nicaragua	-	-	1,977	1,977
India	-	-	694	347
Total International	513	209	11,810	7,066
Total	2,697	1,571	14,181	8,780

(1)

Includes approximately 464,000 gross (214,000 net) developed acres 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.

(4) We funded a 2-D seismic survey over the acreage in return for a working interest in the concession.

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.

Table of Contents

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,					
	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US	87	59	216	146	120	84
Deepwater Gulf of Mexico	40	21	37	17	29	20
Equatorial Guinea	-	-	307	137	-	-
Israel (1)	198	93	1,209	537	-	-
Cameroon (2)	-	-	-	-	647	323
Total	325	173	1,769	837	796	427

(1) 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.

(2) The acreage in Cameroon is comprised of our Tilapia PSC and our YoYo mining concession. Per our Tilapia PSC, we are required to drill two wells in the initial exploratory phase of our agreement which ends in July of 2012 to be eligible for an initial two year renewal period. Presently, we have drilled one well and we intend to drill the second well required under the agreement in the first half of 2012. At the end of the renewal period, ending in July 2014, there is a relinquishment requirement for 50% (479,000 gross acres) of the Tilapia acreage. Pursuant to the YoYo mining concession, if development is not commenced by December 2014, we will be required to relinquish all 168,000 acres we hold under the mining concession.

During 2011, the US Bureau of Safety and Environmental Enforcement (BSEE) granted one year extensions to the original terms of 26 of our deepwater Gulf of Mexico leases. To be eligible for an extension, each lease had to meet the following three criteria: no oil and gas production on the lease as of May 15, 2011, the lease includes water depths in excess of 500 feet, and the lease is scheduled to expire on or before December 31, 2015. The extensions were granted to allow more time to drill on offshore leases following the Deepwater Moratorium.

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, 2011							
United States (1)	9.6	3.7	13.3	641.2	4.0	645.2	658.5
Equatorial Guinea (1)	0.5	-	0.5	0.5	-	0.5	1.0
Cameroon	-	0.5	0.5	-	-	-	0.5
Senegal/Guinea-Bissau	-	0.3	0.3	-	-	-	0.3
Israel (1)	0.8	-	0.8	-	-	-	0.8
Cyprus (1)	0.7	-	0.7	-	-	-	0.7
China	-	-	-	2.9	-	2.9	2.9
Total	11.6	4.5	16.1	644.6	4.0	648.6	664.7

Year Ended December 31, 2010							
United States (1)	4.8	1.9	6.7	510.6	1.0	511.6	518.3
Equatorial Guinea (1)	-	-	-	2.0	-	2.0	2.0
Israel (1)	0.4	-	0.4	1.0	-	1.0	1.4
North Sea	-	-	-	0.6	-	0.6	0.6
China	-	-	-	2.3	-	2.3	2.3
Total	5.2	1.9	7.1	516.5	1.0	517.5	524.6
Year Ended December 31, 2009							
United States (1)	4.1	1.6	5.7	532.3	2.0	534.3	540.0
Equatorial Guinea (1)	0.5	-	0.5	-	-	-	0.5
Israel (1)	1.1	-	1.1	-	-	-	1.1
North Sea	-	-	-	1.0	-	1.0	1.0
China	-	-	-	0.6	-	0.6	0.6
Total	5.7	1.6	7.3	533.9	2.0	535.9	543.2

(1) Includes successful exploratory wells drilled but not yet producing.

A productive well is an exploratory, development or extension well that is not a dry well. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

As defined in the rules and regulations of the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is part of a development project, which is defined as the means by which petroleum resources are brought to the status of economically producible. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Table of Contents

In addition to the wells drilled and completed in 2011 included in the table above, wells that were in the process of drilling or completing at December 31, 2011 were as follows:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2	1.0	162	97.8	164	98.8
Equatorial Guinea	-	-	4	1.9	4	1.9
Israel	1	0.5	5	2.0	6	2.5
Total	3	1.5	171	101.7	174	103.2

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, 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 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 field under long-term contracts. We have signed contracts and are engaged in active discussions for the sale of natural gas from the Tamar field with existing and new customers including multiple independent power producers, industrial, and cogeneration companies. In addition, we are in the final stages of sales contract negotiation with the IEC, currently our largest purchaser of gas in Israel, which is expected to purchase a significant portion of the Tamar production. 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. As of December 31, 2011, remaining delivery commitments under existing natural gas sales contracts with Israeli customers totaled approximately 311 Bcf gross (146 Bcf, net). The majority of the quantities are expected to be delivered over a three year period with one commitment extending over a ten year period.

Table of Contents

At December 31, 2011, we have recorded 83 Bcf, net, of proved developed natural gas reserves for Israel. Although this quantity of proved developed reserves itself would not be sufficient to meet delivery commitments scheduled within the next three years, we are in the process of developing reserves at Noa, which is scheduled to come online in the second half of 2012, and Tamar, which is scheduled to come online in the second quarter of 2013. We are also studying the potential development of Pinnacles, which, if developed as expected, would also come online in the second half of 2012. Based on the current timing of development plans for Noa and Tamar, and considering the potential development of Pinnacles, we will not be able to meet all contractual delivery commitments for portions of 2012 and 2013. In January 2012, we issued force majeure notices to certain customers under the applicable contracts due to Mari-B depletion and its impact on the reservoir and facilities.

Our gas sales contracts have customary liability cap language that limits our financial exposure in the event we cannot fully deliver the contract quantities. Our liability 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 in the event that no production is available for delivery (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.

Thus far in 2012, we have signed new natural gas sales contracts with Israeli customers to supply approximately 1,120 Bcf, gross (400 Bcf, net), of natural gas over a 16 to 17 year period beginning in late 2013. We expect to fulfill the delivery commitments with proved reserves from the Tamar field offshore Israel and do not expect any shortfall from these contracts. See International – Eastern Mediterranean (Israel and Cyprus) above.

Table of Contents

Significant Purchaser   Glencore Energy was the largest single non-affiliated purchaser of 2011 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 16% of 2011 total oil, gas and NGL sales, or 24% of 2011 crude oil sales. Shell Trading (US) Company (Shell) purchased crude oil and condensate from the North Sea and domestically from the deepwater Gulf of Mexico and the Wattenberg area. Sales to Shell accounted for 12% of 2011 total oil, gas and NGL sales, or 17% of crude oil sales. No other single non-affiliated purchaser accounted for 10% or more of oil and gas sales in 2011. 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 2011 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. 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 international, federal, state, provincial and local levels. 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 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; and
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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.

Examples of other laws affecting our international operations are the Oil Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production in Israel, and the Finance Bill 2011, which increased the rate of the Supplementary Charge levied on oil and gas income in the UK.

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). The BOEM and the BSEE were formerly combined and operated as the Bureau of Ocean Energy Management, Regulation and Enforcement. Under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act, these bureaus 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, and the Occupational Safety and Health Act have certain authority over environmental, health and safety matters affecting our operations as discussed below;

Table of Contents

- 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.

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 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 will be subject to the subpart W reporting requirements.

On July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells which would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed rules include maximum achievable control technology standards for certain equipment not currently subject to such standards. Final action on the proposed rules is expected no later than February 28, 2012.

Most of the states within which we operate have separate agencies with authority to regulate related operational and environmental matters. Examples of such regulation on the operational side include the Greater Wattenberg Area Special Well Location Rule 318A (Rule 318A), which was adopted by the Colorado Oil and Gas Conservation Commission (COGCC) to address oil and gas well drilling, production, commingling and spacing in Wattenberg. 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. 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.

On October 3, 2011, Governor Tom Corbett of Pennsylvania announced his plan for state oversight of the Marcellus Shale natural gas industry. His plan includes numerous recommendations recently proposed by the Marcellus Shale Advisory Commission. Standards related to unconventional drilling would include increases in well setback distances, increases in bonding requirements, increases in penalties, expansion of the distance from a well for which a driller can be liable for environmental damage, and broadening of the Department of Environmental Protection’s authority to withhold or revoke permits. The plan also allows for an impact fee, which would be adopted by counties for use by local communities experiencing the actual impacts of drilling. The fee will be used by local governments, counties and state agencies that are involved in Marcellus Shale natural gas drilling. We are monitoring rule-making activities of the Pennsylvania legislature to assess the possible impact any recommendations could have on our business. Enactment of an impact fee and/or other proposals would likely result in a lower rate of return on our development project.

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.

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, and the remediation of petroleum-product contamination.

Table of Contents

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, has recently become 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 reports associating hydraulic fracturing with groundwater contamination, improper waste disposal, poor air quality and earthquakes.

Hydraulic fracturing requires the use and disposal of significant quantities of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of supply. Recently, there have been reports alleging contamination of drinking water supplies by chemicals linked to the hydraulic fracturing process. For example, in December 2011, the EPA issued a draft report which indicated that studies of a hydraulic fracturing site in Pavillion, Wyoming, not operated by Noble Energy, reportedly found hydraulic fracturing fluids and chemicals associated with natural gas production in deep water monitoring wells (Noble Energy has no interest in this field). The findings are not conclusive, and the EPA intends to submit its draft report to an independent scientific review panel.

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. 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 anticipate the ability to recycle most of the water produced. 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 will 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.

Table of Contents

The EPA has commenced a study of the potential environmental impact of hydraulic fracturing, with initial results of the study anticipated to be available by late 2012. 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.

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. 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 voluntary disclosure information on FracFocus.org for the majority of our wells in Colorado and Wyoming and expect to expand our disclosures to comply with new state requirements and voluntarily disclose in all other areas in which we operate.

Additional Information See:

- Items 1. and 2. Business and Properties – Regulation;
- 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 – Risk and Insurance Program.

Table of Contents

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 five 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, North Sea, and Other International and Corporate. See Item 8. Financial Statements and Supplementary Data – Note 18. Segment Information.

Employees

Our total number of employees increased 6%, from 1,772 at December 31, 2010 to 1,876 at December 31, 2011, in support of our major development and exploration projects. The 2011 year-end employee count includes 135 foreign nationals working as employees in Ecuador, 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; and Canonsburg, Pennsylvania; and in China, Cameroon, Ecuador, 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.

On September 7, 2011, an intermediate appellate court (Superior Court) of Pennsylvania issued an opinion in Butler v. Powers regarding the meaning 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 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 it is contained inside rock. An appeal of the decision has been filed with the Pennsylvania Supreme 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.

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.

Table of Contents

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 and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results of operations 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 and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily average settlement price for the prompt month crude oil contract in 2011 ranged from a high of $113.93 per Bbl to a low of $75.76 per Bbl. The Brent daily average settlement price for the prompt month crude oil contract in 2011 ranged from a high of $126.65 per Bbl to a low of $93.33 per Bbl. The NYMEX monthly settlement price for the prompt month natural gas contract in 2011 ranged from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu.

Thus far in 2012, there have been further declines in natural gas futures and spot prices. For example, the NYMEX January 2012 and February 2012 natural gas contracts settled at $3.08 per MMBtu and $2.68 per MMBtu, respectively. In addition, the quantity of natural gas currently being stored is at historically high levels relative to prior years.

The markets and prices for crude oil and natural gas depend on factors beyond our control, which factors include, among others:

- economic factors impacting global gross domestic product growth rates;
- global demand for crude oil and natural gas;
- global factors impacting supply quantities of crude oil and natural gas;
- the potential long-term impact of an abundance of natural gas from shale (such as that produced from our Marcellus Shale properties) on the global natural gas supply;
- the potential expansion of the global LNG market, including potential exports from the US;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability or armed conflict) in crude oil or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil and natural gas;
- the price and availability of alternative fuels, including coal, solar, wind, nuclear energy and biofuels;
- the long-term impact of the use of natural gas as an alternative fuel on the crude oil market;
- 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; and
- domestic and foreign governmental regulations and taxes.

Continuance of the current low natural gas price environment, further declines in natural gas prices, lack of natural gas storage, or a significant decline in crude oil prices 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 and natural gas 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 failure to develop our reserves;
- limit our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- limit our access to sources of capital, such as equity and long-term debt.

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

- asset impairment charges resulting from reductions in the carrying values of our crude oil and/or natural gas properties at the date of assessment, such as occurred in 2009, 2010 and 2011;
- additional counterparty credit risk exposure on commodity hedges; or
- a reduction in the carrying value of goodwill.

Table of Contents

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.

We currently have an extensive inventory of major development projects, some of which will take several years before first production, such as Tamar, Alen, Gunflint, and Leviathan. Some of these projects, such as oil and gas projects offshore West Africa and the Eastern Mediterranean, have a great deal of 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. In addition, we have expanded our horizontal drilling program in the Niobrara formation and entered into an agreement for the joint development of substantial acreage in the Marcellus Shale.

This level of development activity will require significant effort from our management and technical personnel as well as place additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

In addition, we have increased dependency on third-party technology and service providers and other supply chain participants for these complex projects. Significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure, could adversely affect development of our projects. We may not be able to compensate for, or fully mitigate, these risks.

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

Our operations are primarily 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 most of our current crude oil and natural gas production, each of our major development projects, and most of our exploration potential. In the past several years, we have made several asset divestitures, including non-core, non-strategic assets in the Gulf of Mexico shelf and onshore US, to high-grade and focus our portfolio. We are currently considering the divestiture of additional, non-core onshore US assets from our portfolio.

As a result of these portfolio changes, our operations and production are concentrated in fewer areas. Although none of these areas represented more than 28% of our 2011 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.

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

We have significant international crude oil and natural gas operations compared to companies we consider to be our peers, with approximately 47% of our 2011 total sales volumes coming from international operations, and will be increasing our exposure through our major development projects offshore West Africa and the Eastern Mediterranean. 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:

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renegotiation, modification or nullification of existing contracts, such as may occur pursuant to future proposals of Israel’s Interministerial Committee to Examine Government Policy on Israel’s Natural Gas Economy, 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;

- changes in taxation policies, such as occurred pursuant to the Oil Profits Taxation Law, 2011, which imposed additional income tax on oil and gas production in Israel, and the Finance Bill 2011, which increased the rate of the Supplementary Charge levied on oil and gas income in the UK;
- loss of revenue, property and equipment as a result of actions taken by foreign crude oil and natural gas 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 where in 2011 the Turkish government objected to exploratory activities conducted offshore the Republic of Cyprus, and in Central America where there is a dispute between Nicaragua and Colombia over the maritime border;
- changes in drilling or safety regulations in other countries being considered as a result of the Deepwater Horizon Incident or other recent 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;

Table of Contents

- 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 the UK; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Certain of these risks could be intensified by significant new discoveries in the Levant Basin, where we are currently conducting exploration activities, and other developing basins in the Eastern Mediterranean where there is remaining exploration potential. Large discoveries, such as Leviathan and Cyprus Block 12, 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 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 frequently 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, such as al-Qaida, 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 2011 attacks in Oslo, Norway. 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. Most recently, in January 2012, Islamist militants in Nigeria killed hundreds of people and destroyed government buildings. Extreme violence in the Democratic Republic of the Congo has been attributed to exploitation and trade of conflict minerals.

Middle East Civil unrest, often accompanied by violence, has spread throughout the region. Protestors 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 suspicions that it is trying to develop nuclear weapons. Certain countries have considered actions ranging from economic sanctions to pre-emptive strikes on suspected nuclear sites, and 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.

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 transportation avenues are disrupted, leading to further commodity price volatility;
- capital market reassessment of risk and subsequent redeployment of capital to more stable areas making it more difficult for our partners to obtain financing for potential development projects;
- 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;
- unpredictability of sales of our natural gas in Israel due to periodic disruption of Egyptian supply as a result of pipeline attacks;
- 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; and
- shutdown of a financial system, communications network, or power grid causing a complete disruption of our business activities.

Loss of property and/or interruption of our business plans resulting from hostile acts could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Our 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 significant 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 significant oil spill in the Gulf of Mexico. In 2011, leaks attributed to exploration and production activities occurred offshore the coast of Brazil and in China’s Bohai Bay.

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 addition, the European Commission has recommended that new legislation be enacted to enhance the safety of offshore oil and gas activities.

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 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.

Additional legislation or regulation is being discussed which could require each company doing business in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility (COFR), a certificate required by the Oil Pollution Act of 1990 which evidences a company’s financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

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.

We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Deepwater Horizon Incident and other oil spills is not yet known. Further expansion of safety and performance regulations or an increase in liability for drilling activities 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 minimum financial levels;
- 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.

Our entry into the Marcellus Shale through our joint venture with CONSOL will subject us to certain financial, operational and legal obligations and additional risks associated with crude oil and natural gas development activities in that region.

On September 30, 2011, we finalized a joint venture arrangement with CONSOL where, among other things, we have agreed to develop significant acreage in the Marcellus Shale. This arrangement represents the entry into a new core area for us in which we have no prior operating experience. Under the arrangement, we purchased a 50% interest in CONSOL's undeveloped acreage and have agreed to act as operator on a portion of the acreage. Additionally, we have committed to make significant capital expenditures, including a $2.1 billion Carried Cost Obligation, 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 no prior exploration and development experience in the Marcellus Shale 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;
- our operations in the Marcellus Shale will require significant additional attention and we may not be able to attract and/or retain personnel with the necessary skills to successfully carry out our joint development program;
- our entry into the Marcellus Shale will place additional burdens on our financial resources and internal financial controls;
- 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;
- significant 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 local impact fees in Pennsylvania, such as recommended by the Marcellus Shale Advisory Committee and supported by the governor of Pennsylvania, and/or a severance tax in Pennsylvania, such as has been proposed by various groups in the past, 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.

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.

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

In December 2011, we announced a significant natural gas discovery at the Block 12 prospect offshore Cyprus. Combined with previous significant discoveries at Tamar and Leviathan offshore Israel, these natural gas resources will require exporting to maximize economic value.

We are currently evaluating potential development scenarios for Leviathan and Cyprus Block 12, some of which include export of surplus natural gas to Europe or Asia through development of LNG terminals or underwater pipelines. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. We have a nearly 40% working interest in Leviathan and a 70% working interest in Cyprus Block 12. As a result, we will likely seek partners to provide technical and financial support as well as midstream and downstream expertise.

Failure to execute a successful development scenario 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.

Table of Contents

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 fresh 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 aquifer capacity to provide a local 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 wastes 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.

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 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 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 financial condition, results of operations and cash flows.

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 a wide variety of US and international laws and regulations, such as those involving anti-corruption, competition and antitrust, anti-boycott, 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 Organization for Economic Co-operation 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. Violations of any such laws or regulations could result in substantial civil or criminal fines or sanctions. 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.

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.

Indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2011, we had $4.5 billion of debt, of which $369 million is due within 12 months. Our indebtedness represented 38% of our total book capitalization (sum of debt plus shareholders' equity) at December 31, 2011.

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;

Table of Contents

- 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 and natural gas 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.

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. On January 13, 2012, nine European nations had their credit ratings downgraded by Standard and Poor’s by at least one notch. 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.

Offshore development involves significant 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, 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.

Table of Contents

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 Tamar and 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 highly-rated 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 $1.5 billion in cash and cash equivalents at December 31, 2011, 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 2011. 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 also 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 cannot assure that our hedging transactions will reduce the risk or minimize the effect of volatility in crude oil or natural gas prices or interest rates. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Table of Contents

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 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.

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, Tamar, and Leviathan. 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 flow.

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 and natural gas, and our success in finding, developing and producing new reserves.

If revenues were to decrease as a result of lower crude oil and natural gas 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 – 2012 Capital Investment Program.

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 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 a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. The Act provides for a potential exception from these clearing and cash 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. The Act requires the Commodities Futures and Trading Commission (CFTC) to promulgate rules to define these terms, and final definitions will determine which entities will face additional requirements for clearing, trading and posting of margin. However, the process is incomplete and we are unsure what the final definitions will be or how these definitions will apply to us.

Table of Contents

We use crude oil and natural gas derivative instruments with respect to a portion of our expected 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, we could be required to post significant amounts of cash collateral with our dealer counterparties for our derivative transactions. A sudden, unexpected 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 not only cause significant liquidity issues by reducing our flexibility in using our cash and other sources of funds such as our credit facility, but could also cause us to incur additional debt. In addition, a requirement for our counterparties to post cash 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.

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. A significant number of 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.

We face various risks associated with current global populist movements.

During 2011, 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 movements have appeared worldwide. Populist movements are directed against perceived economic and social inequality. For example, in 2011, the “Occupy Movement”, originally directed against Wall Street in New York City, spread to other cities in the US and multiple countries. The Occupy Movement generally is anti-capitalism and anti-business and has targeted global corporations including financial institutions. During 2011, demonstrators picketed at two ports on the US West Coast, shutting down shipping terminals for up to 24 hours in support of union workers. In many situations, social media channels have been used to organize protestors quickly, making it more difficult to fully prepare for protest activities.

Populist activities could result in the following:

- increased regulation of our business;
- increased regulation of the banking industry;

Table of Contents

- increased corporate income taxes; and
- reduced access to shipping or other transportation services.

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 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 and is particularly pronounced in certain countries in the OECD, including the US, the UK and Israel. 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 and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands, delay or cancel certain projects such as offshore drilling, shale development, and pipeline construction, and limit or ban the use of hydraulic fracturing. For example, 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. 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.

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.

Table of Contents

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. For example, in 2011 in the UK and Israel, we witnessed higher tax rates applicable to our operations. 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.

Many countries are currently experiencing fiscal problems, 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.

Due to pressures from financial markets, local constituents as well as the OECD 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.

For example, the American Jobs Act of 2011 (American Jobs Act), proposed by the President of the United States, contains various measures, including tax increases and other revenue-raising proposals, designed to reduce the federal deficit by $3 trillion. If enacted as proposed, these measures would increase the 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, 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 future years.

In Israel, the Interministerial Committee to Examine Government Policy on Israel's Natural Gas Economy has been charged with the task of proposing a government policy for developing the natural gas economy in Israel. Objectives include ensuring energy security for the economy, encouraging competition among various sectors in the local economy, and generating economic and political benefits for Israel. Among other things, the Interministerial Committee will examine the best policy for safeguarding reserves to provide for local consumption and for exporting natural gas. The Interministerial Committee is expected to present its recommendations by February 29, 2012. We are monitoring the activities of the Interministerial Committee to assess the possible impact any recommendations could have on our business. Certain change 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 projects and render future exploration and development projects uneconomic.

During 2011, the Israeli Antitrust Commissioner initiated review of the Israeli domestic gas market and participation in offshore blocks and leases. The Commissioner has publically expressed concerns regarding ownership concentration on exploration blocks and development projects and its potential impacts on a competitive natural gas price environment and end user electricity costs. We are cooperating 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.

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.

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 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 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.

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. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. 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. The ORD expects to have the initial study results available by late 2012. 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.

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 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 issued GHG monitoring and reporting regulations that went into effect January 1, 2010, and, as amended, required reporting by regulated facilities by September 30, 2011 and annually thereafter. Beyond measuring and reporting, the EPA 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. The EPA has issued final regulations requiring petroleum and natural gas operators meeting a certain emissions threshold to report their GHG emissions to the EPA (Subpart W). The EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

Since approximately 62% of our total 2011 crude oil and NGL production and 48% of our total 2011 natural gas production derive from the US, any laws or regulations that may be adopted to restrict or reduce emissions of US GHGs could require us to incur additional operating costs, increase our development cycle time, and have an adverse effect on demand for the crude oil and natural gas we produce. 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.

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. Currently, substantial uncertainty exists about the nature of potential rules and regulations that could impact the sources and uses of energy in the US. 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.

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;
- 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, piracy, or terroristic acts;
- theft of oilfield equipment and supplies, especially in areas of increased activity such as the DJ Basin and Marcellus Shale;
- hurricanes which could affect our operations in areas such as the Gulf Coast and deepwater Gulf of Mexico, and cyclones, which could affect our operations offshore China;
- volcanoes which could affect our operations offshore Equatorial Guinea;
- flooding, such as occurred in Pennsylvania in 2011, which could affect our operations in low-lying areas such as the Marcellus Shale; 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.

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

Businesses have become increasingly dependent on digital technologies to conduct day-to-day operations. At the same time, cyber incidents, including deliberate attacks or unintentional events, have 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.

The oil and gas industry has become increasingly dependent on digital technologies to conduct 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. 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.

We depend on digital technology, including information systems and related infrastructure, 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.

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.

Table of Contents

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 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; and
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties;
- significant 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.

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 revisions to rules for oil and gas reserves reporting, which we implemented effective December 31, 2009, 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 impact of the SEC’s revisions to oil and gas company reserves reporting requirements;
- assumptions concerning future crude oil and natural gas prices;
- anticipated development cycle time;
- future development costs;
- future operating costs;
- 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.

Table of Contents

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 2012. Exploratory drilling requires significant capital investment and is not always successful. For example, we incurred dry hole expense in 2011 because the Kora-1 and Bwabe exploratory wells offshore West Africa found noncommercial quantities of hydrocarbons.

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.

Exploratory drilling activities may be curtailed, delayed or canceled, resulting in significant exploration expense, as a result of a variety of factors, including:

- title problems;
- 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 significant and have a negative impact on our results of operations and cash flows.

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, Tamar, Leviathan or Cyprus, 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, described above, 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 with significant reserves 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.

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.

Table of Contents

We maintain an ongoing portfolio management program which includes sales of non-core, non-strategic assets, such as the sales of non-core onshore US assets in 2010. 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 assets in 2010. Asset divestitures can generate organizational and operational efficiencies as well as cash for use in our capital investment program or to repay outstanding debt. As a result of the Marcellus Shale acquisition, which effectively focused our US operations in three core areas, we are considering the divestiture of certain onshore US assets from our portfolio.

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.

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 currently 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 is resulting in increased global 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.

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. We defend ourselves vigorously in all such matters.

Because we maintain a diversified portfolio of assets that is balanced between 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. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Table of Contents

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

During 2011, we received two Notices of Alleged Violation (NOAV) from the COGCC regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. At this time, the COGCC has not established a proposed penalty for either NOAV. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

Item 4. [Removed and Reserved]

Table of Contents

Executive Officers

The following table sets forth certain information, as of February 9, 2012, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	61	Chairman of the Board, Chief Executive Officer and Director
David L. Stover (2)	54	President, Chief Operating Officer
Kenneth M. Fisher (3)	50	Senior Vice President, Chief Financial Officer
Ted D. Brown (4)	56	Senior Vice President, Northern Region
Rodney D. Cook (5)	54	Senior Vice President, International
Susan M. Cunningham (6)	56	Senior Vice President, Exploration
Arnold J. Johnson (7)	56	Senior Vice President, General Counsel and Secretary
Andrea Lee Robison (8)	53	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 Royal Dutch Shell plc (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 Shell 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.

Table of Contents

(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.

Table of Contents

PART II

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

Common Stock Our common stock, $3.33 1/3 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
2010			
First Quarter	$ 79.19	$ 68.38	$ 0.18
Second Quarter	81.50	56.23	0.18
Third Quarter	77.63	59.22	0.18
Fourth Quarter	89.00	75.07	0.18
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

On January 24, 2012, the Board of Directors declared a quarterly cash dividend of $0.22 per common share, which will be paid February 21, 2012 to shareholders of record on February 6, 2012.

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 13, 2012, the number of holders of record of our common stock was 674.

Stock Repurchases The following table summarizes repurchases of our common stock occurring fourth quarter 2011.

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)
10/01/11 - 10/31/11	674	$81.58	-	-

11/01/11 - 11/30/11	3,969	95.05	-	-
12/01/11 - 12/31/11	679	93.04	-	-
Total	5,322	$93.08	-	-

(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, 2011.

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	6,365,816	$ 59.47	9,648,770
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	6,365,816	$ 59.47	9,648,770

49

Table of Contents

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2006 to December 31, 2011. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index, and our peer group of companies. The cumulative total return of the common stock of our peer group of companies includes the cumulative total return of our common stock.

At December 31, 2011 our peer group of companies 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.

The comparison assumes $100 was invested on December 31, 2006 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,	2006	2007	2008	2009	2010	2011
Noble Energy, Inc.	$ 100.00	$ 163.17	$ 102.00	$ 149.38	$ 182.30	$ 201.70
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
Peer Group	100.00	142.74	89.81	133.21	150.62	133.60

Table of Contents

Item 6. Selected Financial Data

	Year Ended December 31,				
	2011	2010	2009	2008	2007
(millions, except as noted)					
Revenues and Income (Loss)					
Total Revenues	$ 3,763	$ 3,022	$ 2,313	$ 3,901	$ 3,272
Net Income (Loss)	453	725	(131)	1,350	944
Per Share Data					
Earnings (Loss) Per Share					
Basic	$ 2.57	$ 4.15	$ (0.75)	$ 7.83	$ 5.52
Diluted	2.54	4.10	(0.75)	7.58	5.45
Cash Dividends Per Share	0.800	0.720	0.720	0.660	0.435
Year-End Stock Price Per Share	94.39	86.08	71.22	49.22	80.66
Weighted Average Shares Outstanding					
Basic	176	175	173	173	171
Diluted	179	177	173	176	173
Cash Flows					
Net Cash Provided by Operating Activities	$ 2,170	$ 1,946	$ 1,508	$ 2,285	$ 2,017
Additions to Property, Plant and Equipment	2,594	1,885	1,268	1,971	1,414
Acquisitions	527	458	-	292	-
Proceeds from Divestitures	77	564	3	131	9
Financial Position					
Cash and Cash Equivalents	$ 1,455	$ 1,081	$ 1,014	$ 1,140	$ 660
Commodity Derivative Instruments - Current	10	62	13	437	15
Property, Plant, and Equipment, Net	12,782	10,264	8,916	9,004	7,945
Goodwill	696	696	758	759	761
Total Assets	16,444	13,282	11,807	12,384	10,831
Long-term Obligations					
Long-Term Debt	4,100	2,272	2,037	2,241	1,851
Deferred Income Taxes	2,059	2,110	2,076	2,174	1,984
Commodity Derivative Instruments	7	51	17	2	83
Asset Retirement Obligations	344	208	181	184	131
Other	401	371	349	300	337
Shareholders' Equity	7,265	6,848	6,157	6,309	4,809
Operations Information					
Consolidated Crude Oil Sales (MBbl/d)	64	64	62	69	77
Average Realized Price ($/Bbl) (1)	$ 100.93	$ 76.46	$ 55.76	$ 82.60	$ 60.61
Consolidated Natural Gas Sales (MMcf/d)	811	787	781	767	687

Average Realized Price ($/Mcf) (1)	$	3.04	$	3.00	$	2.54	$	5.04	$	5.26
Consolidated NGL Sales (MBbl/d) (2)		15		14		10		9		-
Average Realized Price ($/Bbl)	$	48.35	$	41.21	$	27.96	$	50.15	$	-
Proved Reserves										
Crude Oil, Condensate and NGL Reserves (MMBbls)		369		365		336		311		329
Natural Gas Reserves (Bcf)		5,043		4,361		2,904		3,315		3,307
Total Reserves (MMBoe)		1,209		1,092		820		864		880
Number of Employees		1,876		1,772		1,630		1,571		1,398

(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.

(2) Prior to 2008, US NGL sales volumes were included with natural gas volumes. Effective in 2008 we began reporting US NGLs separately where we have the right to take title, which lowered the comparative natural gas sales volumes for 2008.

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

We are a worldwide producer of crude oil and natural gas. Our strategy is to achieve growth in value and cash flows through the continued expansion of a high quality portfolio of producing assets that is balanced and diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Strategy We seek to achieve growth in value and cash flows through exploration success and the development of a high quality, diverse 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 we augment that with a periodic, opportunistic new business development (mergers and acquisition) capability. We manage the portfolio for high returns and to ensure geographic portfolio balance. We actively manage our portfolio with periodic divestments to "high grade" the portfolio. 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; Galapagos and Gunflint in the deepwater Gulf of Mexico; Tamar and Leviathan, offshore Israel; Aseng (which commenced oil production in November 2011), Alen 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 balanced 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 to gain momentum during 2011 with the US ending in a slightly better position than the previous year. China and other emerging markets continue to maintain solid growth rates and contribute strongly to global commodity demand. However, the European economy remains threatened by the Eurozone debt crisis and its effects on economic growth rates. The global crude oil market has generally been robust driven by increased demand in developing countries coupled with continued threats to the global crude oil supply system and shrinking OPEC spare production capacity supporting oil price levels. The global LNG market has strengthened after the impact of the tsunami on Japan's nuclear plants and the announced phase out of

German nuclear generation capacity. In the US, the application of horizontal drilling technology significantly changed the natural gas markets, resulting in an oversupply of natural gas and significantly lower Henry Hub spot and forward prices. Horizontal technology has also been applied to liquids (oil and natural gas liquids) plays and has yielded significant growth in onshore US liquids production. Crude oil transportation constraints in the US resulted in a disparity between WTI and Brent pricing, and Brent pricing remains somewhat higher than WTI. Third party service costs face some inflationary pressures in response to robust US drilling activity.

2011 Results Despite the uncertain economic situation, 2011 was another strong year for Noble Energy as we continued to lay the foundation for significant future growth from our major development projects while maintaining our strong balance sheet and financial flexibility. Our strategic entry into the Marcellus Shale Joint Venture strengthens and rebalances our portfolio, providing a new, material growth area which we believe will contribute to future reserves, production, and cash flows. The Marcellus Shale is a low-cost natural gas play located near the nation's largest natural gas market. The innovative structure of the joint venture, with a carried cost arrangement that is suspended when natural gas prices decline to certain predetermined levels, ensures economic alignment with our partner at low natural gas prices.

In the deepwater Gulf of Mexico, we contributed to leading our industry back to work, receiving the first post-moratorium drilling permit, and had an exploration success at our Santiago prospect. We are working to strengthen the industry and our company by continuing to enhance safety processes and spill response through the development of a Safety and Environmental Management System (SEMS) in response to new workplace safety rules. We also have a membership in Helix Energy Solutions Group, an oil spill containment response group.

Table of Contents

In Equatorial Guinea we brought our Aseng major development project online earlier than scheduled and 13% under budget, significantly adding to our liquids production, which is sold at prices linked to Brent. We continued to make progress on our major development project Alen, continued exploration activities offshore Cameroon, and farmed into a significant acreage exploration position in Senegal/Guinea-Bissau.

In the Eastern Mediterranean, sales volumes increased as we continued to support the Israeli market as it experienced interruptions in Egyptian gas supplies. We made significant progress on our Tamar project, which remains on schedule and on budget with first sales targeted for second quarter 2013. We continued appraisal work at the Leviathan discovery and made another significant natural gas discovery offshore Cyprus.

Our 2011 financial results included the following:

- net income of $453 million as compared with $725 million for 2010;
- gain on divestitures of $25 million as compared with $113 million for 2010;
- asset impairment charges of $759 million as compared with $144 million for 2010;
- gain on commodity derivative instruments of $42 million (including unrealized mark-to-market loss of $22 million) as compared with $157 million gain on commodity derivative instruments (including unrealized mark-to-market gain of $70 million) for 2010;
- diluted earnings per share of $2.54, as compared with $4.10 for 2010;
- cash flows provided by operating activities of $2.2 billion, as compared with $1.9 billion in 2010;
- capital spending on a cash basis of $3.2 billion (including $596 million for the Marcellus Shale asset acquisition) as compared with $2.3 billion in 2010 (including $458 million for the DJ Basin acquisition);
- issuance of $850 million of 30-year unsecured notes and $1 billion of 10-year unsecured notes;
- new credit agreement providing a $3 billion unsecured revolving credit facility (replacing our $2.1 billion credit facility);
- ending cash and cash equivalents balance of almost $1.5 billion at December 31, 2011, as compared with $1.1 billion at December 31, 2010;
- total liquidity of $4.5 billion at December 31, 2011, consisting of year-end cash balance plus funds available under our credit facility, as compared with $2.8 billion at December 31, 2010; and
- year-end ratio of debt-to-book capital of 38%, as compared with 25% at December 31, 2010.

Significant operational highlights for 2011 included the following:

Overall

- total sales volumes of 222 MBoe/d, a 3% increase as compared with 2010; and
- year-end proved reserves of 1.2 BBoe, an increase of 11% from year-end 2010.

Onshore United States

- closed the Marcellus Shale Joint Venture which produced an average of 74 MMcf/d of natural gas, net to our interest, in the fourth quarter of 2011;
- increased DJ Basin volumes to 66 MBoe/d in the fourth quarter of 2011 with horizontal production exiting the quarter at 17 MBoe/d;
- drilled longest-ever horizontal Niobrara well in the DJ Basin with over 9,100 foot lateral in the Wattenberg field; and
- drilled and completed 64 horizontal wells in the DJ Basin Niobrara formation and added a fifth rig to the program.

Deepwater Gulf of Mexico

- announced Santiago discovery and increased the expected initial net production at the Galapagos project to over 10 MBbl/d of crude oil; and
- received Gunflint drilling permit.

International

- startup of Aseng, which exited the year producing 19 MBbl/d of crude oil, net to our interest;
- a world-class discovery offshore Cyprus;
- oil discovery at the Carla prospect in Block O, offshore Equatorial Guinea;
- sanctioned the development plan for the Noa project, offshore Israel, and drilled two development wells;
- natural gas sales in Israel of 173 MMcf/d, net to our interest;
- completed transfer of assets and exit from Ecuador;
- completed seismic acquisition of 3-D data offshore Nicaragua; and
- successfully appraised the Leviathan discovery offshore Israel.

Table of Contents

Acquisitions and Divestitures

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 strengthens and rebalances our portfolio, providing a new, material growth area, which 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. It significantly increases our inventory of low risk repeatable 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, provide balance to our rapidly expanding international programs.

Under the terms of the agreement, we acquired 50% interests in approximately 628,000 net undeveloped acres, existing Marcellus Shale production, and existing infrastructure for approximately $1.3 billion, including post-closing adjustments. Payments will be made in three annual installments, with the first installment made at closing. We will pay an additional $2.1 billion in the form of a carry of CONSOL's drilling and completion costs. The carry, which we expect to extend over approximately eight years or more, is capped at $400 million annually and suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices. Initially, we will be the designated operator of the wet-gas areas (areas with more condensate or liquids) and CONSOL will be the designated operator of the dry-gas areas (areas with little or no condensate or liquids).

As a result of this transaction, we are now focusing on three core areas within the US: the DJ Basin; the Marcellus Shale; and the deepwater Gulf of Mexico. We are also considering the divestiture of certain non-core onshore US properties from our portfolio.

Exit from Ecuador In 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 by November 23, 2010. It also allows the Ecuadorian government to nationalize oil and gas fields if a private operator does not comply with local laws.

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, which was terminated by the government of Ecuador on November 25, 2010, 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.

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 included properties located in the DJ Basin, one of our core operating areas. 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, and will provide significant growth potential. Included in the purchase were 323,000 total net acres, nearly 183,000 of which are located in the DJ Basin.

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 were 3% higher in 2011 as compared with 2010. Our mix of sales volumes was 39% global liquids, 32% international natural gas with long-term pricing contracts, and 29% US natural gas. In the US, production was higher in the onshore areas due to record production in Wattenberg primarily due to continued horizontal Niobrara field development and the addition of the Marcellus Shale production in the fourth quarter of 2011. Additionally, international oil production was higher due to Aseng commencing production in November 2011.

In Israel, there was an increase in demand for natural gas to produce electricity due to disruptions with the Egyptian imports during 2011 and warmer weather which led to a higher percentage of the demand being met by production from our properties.

Commodity Price Changes and Hedging Historically, oil and gas prices have exhibited significant volatility. The liquids (crude oil) market remained relatively robust during 2011, benefiting from the continued global economic recovery and continued threats to the global oil supply system. However, the domestic natural gas market continued to weaken significantly, primarily due to an abundant supply and above average levels of gas in storage. US natural gas prices remain volatile and prices are still significantly below the prices realized in 2007 - 2008. See Item 6. Selected Financial Data.

Table of Contents

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 2012. 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 2011, we recorded impairment charges of $759 million mainly related to our onshore US assets. The significant decline in spot and five-year forward natural gas prices, approximately 17% over the five-year forward period, during the fourth quarter of 2011 was the major triggering event for most of these impairments. Field performance issues also contributed to impairments. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

OPERATING OUTLOOK

2012 Outlook We remain hopeful for a continued recovery of the global economy; however, we continue to monitor the outlook for the global economy and numerous critical factors including the Chinese economic growth rates, the European debt crisis and its potential impacts on global economic growth and the banking and financial sectors, the US federal budget deficit situation, and commodity prices. We expect crude oil prices to remain at or above current levels as long as the global economic recovery continues, OPEC spare production capacity shrinks as a percentage of global oil demand and threats remain to the global crude oil supply system. Disruption to the global oil supply system could trigger volatility and price spikes with resulting economic shocks which ultimately lead to demand destruction and price declines. We also expect US natural gas prices to remain low as long as the US drilling rig count remains near current levels, storage remains at high levels, and production growth continues. 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 2012 Capital Investment Program below.

2012 Production Our expected crude oil, natural gas and NGL production for 2012 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;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- ramp-up of development activity in the Marcellus Shale;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations, in the North Sea 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 and competing deliveries of natural gas from Egypt and commencement of production from the Noa field and Pinnacles project (if approved by partners as expected) offshore Israel;

- variations in West Africa and North Sea 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;
- 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/or divestments of non-core operating assets; and
- potential shut-in of US producing properties if storage capacity becomes unavailable.

2012 Capital Investment Program Our total capital investment program for 2012 is estimated at $3.5 billion. The capital investment program allocates approximately 51% to onshore US, 7% for deepwater Gulf of Mexico, 22% to the Eastern Mediterranean, 14% to West Africa and 6% to corporate and other. Exploration and appraisal activity within these geographic areas is expected to receive 16% of total capital.

Table of Contents

We expect that the 2012 capital investment program will 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 onshore US 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;
- property acquisitions and divestitures;
- 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 Act, on our business practices.

Exploration Program We have significant future exploration potential, primarily in the onshore US, deepwater Gulf of Mexico, offshore West Africa, Eastern Mediterranean and other international areas where we hold acreage positions. As of January 2012, we have returned to drilling at the Leviathan-1 well, which was suspended during 2011, in order to evaluate additional intervals for the existence of other hydrocarbons. Results from the deeper tests, which have a low chance of success, are expected the first half of 2012.

We recently resumed appraisal drilling at Gunflint in the deepwater Gulf of Mexico. In addition, we are planning further exploratory drilling in the Gulf of Mexico, offshore West Africa and in the Eastern Mediterranean.

Exploration activity, particularly offshore, requires significant capital investment. We do not always encounter commercially productive reservoirs through our drilling operations and, as a result, could incur significant dry hole cost. We are planning an active exploratory drilling program in 2012. As a result, dry hole cost could be significant.

Major Development Project Inventory Our current inventory of major development projects includes the horizontal Niobrara, Marcellus Shale, Galapagos, Tamar, Alen, Diega, Gunflint, Leviathan, and other West Africa gas projects. These projects will require significant capital investments. For example, total development costs for the first phase of the Tamar natural gas project are estimated at $3.0 billion ($1.1 billion for our share).

As noted above, we expect to spend substantial amounts on our major development projects in 2012. 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. We commenced oil production from the first of our major projects, Aseng, in November 2011 and ahead of the original schedule. First production from our remaining major offshore development projects is targeted to occur when Galapagos begins to produce in the second quarter of 2012, and Tamar begins to produce in second quarter 2013. Once these two major projects begin producing along with Aseng, we expect to begin generating sufficient amounts of cash flow to self-fund the remaining discovered major projects investments.

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

Potential for Future Asset Impairments   The US natural gas market remains weak. A further decrease in forward natural gas prices during 2012 could result in impairment charges. Certain of our onshore US properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These assets, which have a combined net book value of approximately $1.0 billion at December 31, 2011, are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. 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 natural gas prices alone could result in an impairment of properties that are sensitive to declines in natural gas prices. A significant drop in global oil prices may also trigger impairment. See Item 1A. Risk Factors – Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results of operations and the price of our common stock. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Potential Changes in Fiscal Regimes and Market Regulations   Future economic and political changes in the US or other countries in which we operate could result in governments enacting additional taxes and/or other market interventions, which could be detrimental to oil and gas companies. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Table of Contents

During 2011, fiscal regime changes occurred in both Israel and the UK. See Item 8. Financial Statements and Supplementary Data – Note 13. Income Taxes.

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 Jobs Act and the Israeli Interministerial Committee.

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. During 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 fuelling extreme weather and predicted that there will be an escalation of impacts on people and economies.

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, 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 2011, the annual conference of parties reconvened in Durban, South Africa to continue pursuing the global accord, committing countries to cut GHG emissions. The parties, including both developed and developing countries, renewed the Protocol and committed to work on an agreement that would be legally binding on all parties, to be written by 2015 and to come into force after 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.

Table of Contents

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 61% of our 2011 total sales volume 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 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, tornados 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 Account Policies.

RESULTS OF OPERATIONS

Selected financial information is as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions, except per share)			
Total Revenues	$3,763	$3,022	$2,313
Total Operating Expenses	3,023	2,070	2,371
Operating Income (Loss)	740	952	(58)
Total Other (Income) Expense	25	(79)	206
Income (Loss) Before Income Taxes	715	1,031	(264)
Net Income (Loss)	453	725	(131)
Earnings (Loss) Per Share			

Basic	$2.57	$4.15	$(0.75)
Diluted	2.54	4.10	(0.75)

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

- $48 million increase in total production expense;
- $34 million increase in exploration expense;
- $82 million increase in DD&A expense;
- $64 million increase in general and administrative expense;
- $88 million decrease in net gain on asset sales;
- $615 million increase in asset impairment charges; and
- $115 million decrease in gain on commodity derivative instruments;

Table of Contents

offset by:

- $741 million increase in total revenues due to higher commodity prices and higher sales volumes.

Factors contributing to the increase in income (loss) before income taxes in 2010 as compared with 2009 included the following:

- $709 million increase in total revenues due primarily to higher commodity prices;
- $460 million decrease in asset impairment charges;
- $91 million increase in net gain on asset sales; and
- $157 million mark-to-market gain on commodity derivative instruments as opposed to a $110 million mark-to-market loss in 2009;

offset by:

- $45 million increase in total production expense;
- $101 million increase in exploration expense; and
- $67 million increase in DD&A expense.

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:

(millions)	Crude Oil & Condensate	Natural Gas	NGLs	Total
2009 Sales Revenues	$1,261	$701	$98	$2,060
Changes due to				
Increase in Sales Volumes	48	5	40	93
Increase in Sales Prices Before Hedging	447	129	65	641
Change in Amounts Reclassified from AOCL	39	(1)	-	38
2010 Sales Revenues	1,795	834	203	2,832
Changes due to				
Increase in Sales Volumes	3	55	21	79
Increase in Sales Prices Before Hedging	556	9	40	605
Change in Amounts Reclassified from AOCL	19	1	-	20
2011 Sales Revenues	$2,373	$899	$264	$3,536

Table of Contents

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) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2011							
United States (2)	38	388	15	117	$95.19	$3.90	$48.35
Equatorial Guinea (3) (4)	14	245	-	56	107.57	0.27	-
Israel	-	173	-	29	-	4.86	-
North Sea	8	5	-	9	112.97	8.11	-
China	4	-	-	4	106.19	-	-
Total Consolidated Operations	64	811	15	215	100.93	3.04	48.35
Equity Investees (6)	2	-	5	7	108.76	-	72.71
Total	66	811	20	222	$101.13	$3.04	$54.84
Year Ended December 31, 2010							
United States (2)	39	400	14	119	$75.03	$4.17	$41.21
Equatorial Guinea (3) (4)	11	226	-	49	78.44	0.27	-
Israel	-	130	-	22	-	4.03	-
North Sea	10	6	-	11	80.24	5.35	-
Ecuador (5)	-	25	-	4	-	-	-
China	4	-	-	4	75.15	-	-
Total Consolidated Operations	64	787	14	209	76.46	3.00	41.21
Equity Investees (6)	2	-	5	7	77.98	-	53.68
Total	66	787	19	216	$76.50	$3.00	$44.90
Year Ended December 31, 2009							
United States (2)	37	397	10	113	$55.19	$3.61	$27.96
Equatorial Guinea (3) (4)	14	239	-	54	55.94	0.27	-
Israel	-	114	-	19	-	3.47	-
North Sea	7	5	-	8	59.51	5.75	-
Ecuador	-	26	-	4	-	-	-
China	4	-	-	4	54.40	-	-
Total Consolidated Operations	62	781	10	202	55.76	2.54	27.96
	2	-	6	8	59.51	-	36.03

Equity Investees (6)							
Total	64	781	16	210	$55.87	$2.54	$31.20

(1) Natural gas is converted on the basis of six Mcf of gas per one Bbl 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 Bbl of oil equivalent for natural gas is significantly less than the price for a Bbl of oil.

(2) Average realized crude oil and condensate prices reflect reductions of $1.32 per Bbl for 2010 and $2.13 per Bbl for 2009 from hedging activities. Average realized natural gas prices reflect a decrease of $0.01 per Mcf for 2010 from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis.

The price reductions resulted from hedge gains and losses that had been previously deferred AOCL. All hedge gains or losses relating to US production had been reclassified to revenues by December 31, 2010.

(3) Average realized crude oil and condensate prices reflect a reduction of $5.57 per Bbl for 2009 from hedging activities.

The price reduction resulted from hedge losses that had been previously deferred in AOCL. All hedge gains or losses relating to Equatorial Guinea production had been reclassified to revenues by December 31, 2009.

(4) Natural gas from the Alba field in Equatorial Guinea is sold 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.

(5) Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales for 2010 and 2009 were eliminated for accounting purposes. Electricity sales (through May 2011) are included in other revenues. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

(6) Volumes represent sales of condensate and LPG from the Alba Plant in Equatorial Guinea. See Income from Equity Method Investees below.

Table of Contents

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,					
	2011		2010		2009	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
United States	$ (3.22)	$ 0.77	$ (0.65)	$ 0.76	$ 12.26	$ 1.73
Equatorial Guinea	-	-	(3.41)	-	15.36	-
Total Consolidated Operations	(1.89)	0.37	(1.00)	0.40	10.86	0.91
Total	(1.84)	0.37	(0.97)	0.40	10.55	0.91

Crude Oil and Condensate Sales Revenues from crude oil and condensate sales increased by a net $578 million, or 32%, in 2011 as compared with 2010 due to the following:

- a 32% 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 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;
- a decrease in deepwater Gulf of Mexico volumes due to natural field decline and third party downstream facility constraints; and
- a decrease in North Sea volumes due to downtime in the Dumbarton field for GP III FPSO maintenance.

Revenues from crude oil and condensate sales increased by a net $534 million, or 42%, in 2010 as compared with 2009 due to the following:

- a 37% increase in total consolidated average realized prices due to increased demand resulting from the global economic recovery;
- increased production due to ongoing development activity in the DJ Basin, including the horizontal Niobrara drilling program;
- additional production from the DJ Basin asset acquisition in March 2010;
- crude oil production from a Swordfish side track oil well that commenced production first quarter 2010;
- renewed production from Ticonderoga in the deepwater Gulf of Mexico which was off-line first quarter 2009 as a result of hurricane damage to third-party processing and pipeline facilities; and
- an increase in North Sea sales volumes primarily as a result of increased deliverability at the Dumbarton complex, which included the addition of two Lochranza wells in 2010;

partially offset by

- a decrease in onshore US volumes due to the divestment of non-core crude oil producing assets;
-

a decrease in deepwater Gulf of Mexico volumes due to natural field decline and third party downstream facility constraints;

- a decrease in onshore US volumes due to natural field decline in the Mid-Continent and Gulf Coast areas; and
- a decrease in Equatorial Guinea sales volumes due to the planned shut-down of the Alba field for facilities maintenance and repair during 2010 and the timing of liftings.

Revenues from crude oil and condensate sales included deferred losses of $19 million in 2010 and $58 million in 2009 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 increased by a net $65 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;

Table of Contents

- 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 sales increased by a net $133 million, or 19%, in 2010 as compared with 2009 due to the following:

- an increase in total consolidated and US average realized prices due to increased demand resulting from the economic recovery;
- an increase in Israel average realized prices under the terms of a natural gas sales contract entered into in the third quarter of 2009;
- increased production due to ongoing development activity in the DJ Basin, including the horizontal Niobrara drilling program;
- additional production from the DJ Basin asset acquisition in March 2010; and
- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by increased electricity production due to warmer weather and lower levels of competitor natural gas imports from Egypt;

partially offset by

- a decrease in Equatorial Guinea sales volumes due to the planned shut-down of the Alba field for facilities maintenance and repair; 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. The effect of hedging activities for 2009 was de minimis. 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 and deepwater Gulf of Mexico. NGL sales revenues increased $61 million, or 30%, 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.

NGL sales revenues increased $105 million during 2010 as compared with 2009 due to an increase in sales volumes from ongoing development activity in the DJ Basin, including our horizontal Niobrara drilling program, as well as an increase in consolidated average realized prices which benefited from increased demand resulting from the global economic recovery.

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.

Table of Contents

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

	Year Ended December 31, 2011	2010	2009
Net Income (in millions)			
AMPCO and Affiliates	$ 68	$ 29	$ 18
Alba Plant	125	89	66
CONE	2	-	-
Dividends (in millions)			
AMPCO and Affiliates	86	44	29
Alba Plant	139	95	63
Sales Volumes			
Methanol (MMgal)	155	129	145
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	5	6
Average Realized Prices			
Methanol (per gallon)	$ 1.05	$ 0.84	$ 0.60
Condensate (per Bbl)	108.76	77.98	59.51
LPG (per Bbl)	72.71	53.68	36.03

AMPCO and Affiliates 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.

Net income from AMPCO and affiliates increased in 2010 as compared with 2009 due to an increase in average realized methanol prices from increased demand due to the global economic recovery. During fourth quarter 2010, the methanol plant successfully completed a major turnaround in 31 days. Production resumed on October 30, 2010.

Alba Plant 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.

Net income from Alba Plant increased in 2010 as compared with 2009 due to an increase in average realized condensate and LPG prices from increased demand due to the 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. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Other Revenues Other revenues were as follows:

	Year Ended December 31, 2011	2010	2009
(millions)			
Other Revenues	$32	$72	$169

Other revenues include electricity sales 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:

(millions)	2011	Inc (Dec) from Prior Year	2010	Inc (Dec) from Prior Year	2009
Production Expense	$618	8%	$570	9%	$525
Exploration Expense	279	14%	245	70%	144
Depreciation, Depletion and Amortization	965	9%	883	8%	816
General and Administrative	341	23%	277	17%	237
Gain on Divestitures	(25)	(78%)	(113)	414%	(22)
Asset Impairments	759	427%	144	(76%)	604
Other Operating Expense, Net	86	34%	64	(4%)	67
Total	$3,023	46%	$2,070	(13%)	$2,371

Changes in operating costs and expenses are discussed below.

Table of Contents

Production Expense   Components of production expense were as follows:

(millions, except per unit)	Total per BOE	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate(1)
Year Ended December 31, 2011							
Lease Operating Expense (2)	$ 5.07	$ 397	$ 254	$ 53	$ 12	$ 51	$ 27
Production and Ad Valorem Taxes	1.86	146	102	-	-	-	44
Transportation Expense	0.97	75	65	-	-	7	3
Total Production Expense (3)	$ 7.90	$ 618	$ 421	$ 53	$ 12	$ 58	$ 74
Total Production Expense per BOE		$ 7.90	$ 9.85	$ 2.64	$ 1.16	$ 17.17	N/M
Year Ended December 31, 2010							
Lease Operating Expense (2)	$ 4.93	$ 376	$ 258	$ 43	$ 9	$ 47	$ 19
Production and Ad Valorem Taxes	1.64	125	103	-	-	-	22
Transportation Expense	0.91	69	59	-	-	8	2
Total Production Expense (3)	$ 7.48	$ 570	$ 420	$ 43	$ 9	$ 55	$ 43
Total Production Expense per BOE		$ 7.48	$ 9.69	$ 2.38	$ 1.15	$ 13.37	N/M
Year Ended December 31, 2009							
Lease Operating Expense (2)	$ 5.05	$ 372	$ 258	$ 45	$ 9	$ 43	$ 17
Production and Ad Valorem Taxes	1.28	94	81	-	-	-	13
Transportation Expense	0.80	59	52	-	-	4	3
Total Production Expense (3)	$ 7.13	$ 525	$ 391	$ 45	$ 9	$ 47	$ 33
Total Production Expense per BOE		$ 7.13	$ 9.51	$ 2.30	$ 1.36	$ 17.50	N/M

N/M Amount is not meaningful. See (1) below.
(1) Other international includes China and unallocated expenses incurred at the corporate level.
(2) 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.
(3) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

Lease Operating Expense   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, as discussed above;

- higher operating costs associated with the Aseng field which began producing in November 2011; and
- higher operating costs at the North Sea Dumbarton field related to maintenance at the GP III FPSO;

offset by

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

Lease operating expense was flat in 2010 as compared with 2009. Changes included following:

- an increase in US sales volumes due to ongoing development activity in DJ Basin, including horizontal drilling in the Niobrara formation;
- an increase in US production volumes due to the DJ Basin asset acquisition; and
- an increase in North Sea lease operating expense due to higher sales volumes;

offset by

- a decrease in Equatorial Guinea lease operating expense due to the planned shut-down of the Alba field for facilities maintenance and repair; and
- the sale of non-core assets in the Mid-Continent and Illinois Basin areas, which had higher lease operating costs.

Production and Ad Valorem Tax Expense In the US, the sale of certain non-core Oklahoma and Illinois Basin assets in 2010 and natural field decline in the Mid-Continent area resulted in a decrease in production and ad valorem taxes in 2011 as compared with 2010. 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.

Production and ad valorem tax expense for 2010 increased as compared with 2009 due to higher commodity prices.

Transportation Expense 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.

Transportation expense increased in 2010 as compared with 2009 due to an increase in crude oil and condensate production in the DJ Basin and the use of a new interstate crude oil transportation pipeline system to market production.

Table of Contents

Unit Rate Per BOE   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.

The unit rate of total production expense per BOE increased for 2010 as compared with 2009 primarily due to increases in production and ad valorem taxes and transportation expense.

Oil and Gas Exploration Expense   Exploration expense was as follows:

	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	North Sea	Other Int'l, Corporate (3)
(millions)						
Year Ended December 31, 2011						
Dry Hole Expense	$105	$46	$59	$-	$-	$-
Seismic	63	33	1	4	-	25
Staff Expense	96	22	7	2	1	64
Other	15	15	-	-	-	-
Total Exploration Expense	$279	$116	$67	$6	$1	$89
Year Ended December 31, 2010						
Dry Hole Expense	$58	$54	$3	$-	$-	$1
Seismic	102	51	5	11	-	35
Staff Expense	69	10	6	2	3	48
Other	16	15	-	-	-	1
Total Exploration Expense	$245	$130	$14	$13	$3	$85
Year Ended December 31, 2009						
Dry Hole Expense	$11	$8	$3	$-	$-	$-
Seismic	62	47	-	15	-	-
Staff Expense	65	13	10	1	2	39
Other	6	6	-	-	-	-
Total Exploration Expense	$144	$74	$13	$16	$2	$39

(1) West Africa includes Equatorial Guinea, Cameroon, and Senegal/Guinea-Bissau.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other international, corporate includes China and various international new ventures such as offshore Nicaragua and offshore France.

Oil and gas exploration expense for 2011 increased by $34 million, or 14%, as compared with 2010. 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 seismic information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, offshore Nicaragua, offshore France, and offshore Cyprus. Increases in staff expense were due to new ventures mainly offshore Nicaragua and offshore France.

Oil and gas exploration expense for 2010 increased by $101 million, or 70%, as compared with 2009. US dry hole expense was associated with the Double Mountain exploration well in the deepwater Gulf of Mexico, which found noncommercial quantities of hydrocarbons. Seismic expenditures related to the Central Gulf of Mexico lease sale, and the acquisition of 3-D seismic information for offshore Israel, Cameroon, Nicaragua, and France.

Exploration expense included stock-based compensation expense of $11 million in 2011, $10 million in 2010, and $9 million in 2009.

Table of Contents

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

	Year Ended December 31,		
	2011	2010	2009
(millions, except unit rate)			
United States	$758	$719	$689
Equatorial Guinea	69	39	38
Israel	25	22	20
North Sea	87	64	34
Other International, Corporate, and Other	26	39	35
Total DD&A Expense (1)	$965	$883	$816
Unit Rate per BOE (2)	$12.32	$11.57	$11.08

(1) DD&A expense includes accretion of discount on asset retirement obligations of $20 million in 2011, $17 million in 2010, and $14 million in 2009.
(2) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

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.

Total DD&A expense increased for 2010 as compared with 2009 due to the following:

- higher sales volumes in the DJ Basin, Piceance Basin and Western Oklahoma areas of our US operations, which have higher DD&A rates relative to sales volume from Equatorial Guinea and Israel;
- ongoing development activity in DJ Basin, including horizontal drilling in the Niobrara formation; and
- higher sales volumes in the North Sea;

partially offset by

- lower DD&A expense in the Mid-Continent area which has a reduced net book value resulting from an impairment recorded at the end of 2009; and
- the cessation of DD&A associated with assets sold or held-for-sale during the year.

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

	Year Ended December 31,		
	2011	2010	2009
G&A Expense (in millions)	$341	$277	$237
Unit Rate per BOE (1)	$4.35	$3.63	$3.22

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

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 increased for 2010 as compared with 2009 primarily due to additional expenses relating to personnel and office costs in support of our major development 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 $42 million in 2011, $39 million in 2010, and $36 million in 2009. See Item 8. Financial Statements and Supplementary Data – Note 15. Stock-Based Compensation.

Table of Contents

Gain on Divestitures Gain on divestitures was as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Net Gain on Divestitures	$(25)	$(113)	$(22)

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

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. Net gain on asset sales for 2009 includes a $24 million gain on the sale of our Argentina assets. We sold our Argentina assets in 2008; however, recognition of the gain on the sale was deferred until 2009 when the Argentine government approved the sale. 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,		
	2011	2010	2009
(millions)			
Asset Impairments	$759	$144	$604

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,		
	2011	2010	2009
(millions)			
Deepwater Gulf of Mexico Moratorium Expense	$18	$27	$-
Electricity Generation Expense	26	39	18
Write-down of SemCrude L.P. Receivable	-	-	12
Loss on Involuntary Conversion	4	-	-
Other, Net	38	(2)	37
Total	$86	$64	$67

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,		
	2011	2010	2009
(millions)			
(Gain) Loss on Commodity Derivative Instruments	$(42)	$(157)	$110
Interest, Net of Amount Capitalized	65	72	84

Other Non-Operating (Income) Expense, Net	2	6	12
Total	$25	$(79)	$206

(Gain) Loss 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 16. Fair Value Measurements and Disclosures.

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

	Year Ended December 31,		
	2011	2010	2009
(millions, except per unit)			
Interest Expense	$197	$139	$129
Capitalized Interest	(132)	(67)	(45)
Interest Expense, Net	$65	$72	$84
Unit Rate per BOE (1)	$0.83	$0.94	$1.13

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

67

Table of Contents

Interest expense prior to the reduction of capitalized interest increased $58 million in 2011 as compared with 2010. The increase in interest expense prior to the reduction of capitalized interest resulted 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 $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-term projects in the deepwater Gulf of Mexico, West Africa, and Eastern Mediterraean 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 expense prior to the reduction of capitalized interest increased $10 million from 2009 to 2010 due to the higher interest rate associated with our $1 billion 8¼% senior unsecured notes due March 1, 2019, which were outstanding for a full 12 months in 2010 as compared with ten months in 2009. The increase in interest expense prior to the reduction of capitalized interest was more than offset by an increase in the amount of interest capitalized due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, West Africa, and Israel.

Interest is capitalized on exploration and development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest is related to long lead-time projects in the deepwater Gulf of Mexico, West Africa and Eastern Mediterraean. 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, 2011, approximately 49% 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 $8 million in 2011, $15 million in 2010, and $23 million in 2009. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit Plans.

Interest Income   Interest income includes $3 million in 2010 and $11 million in 2009 related to interest received on the refund of deepwater Gulf of Mexico royalties.

Income Tax Provision (Benefit)   The income tax provision (benefit) was as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Income Tax Provision (Benefit)	$262	$306	$(133)
Effective Rate	37%	30%	50%

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

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,		
	2011	2010	2009
(MMBOE)			
Proved Reserves Beginning of Year	1,092	820	864
Revisions of Previous Estimates	(50)	5	(64)
Extensions, Discoveries and Other Additions	180	360	95
Purchase of Minerals in Place	68	47	2
Sale of Minerals in Place	-	(61)	-
Production	(81)	(79)	(77)
Proved Reserves End of Year	1,209	1,092	820

Table of Contents

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, 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.

- 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, will be pursued for development, and a negative revision of 2 MMBoe due to well performance; and

- changes for the year ended December 31, 2009 included a negative revision of 37 MMBoe due to reclassifications of proved undeveloped reserves to probable reserves as a result of the SEC's new five year development rule and 27 MMBoe due to lower natural gas prices, partially offset by positive revisions due to higher crude oil prices.

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

- changes for the year ended December 31, 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.

- 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; and

- changes for the year ended December 31, 2009 included US additions of 67 MMBoe, which were primarily driven by the execution of low-risk development projects onshore in Wattenberg and the Piceance Basin, as well as from the sanctioning of the development plan for Galapagos in the deepwater Gulf of Mexico, and international additions of 28 MMBoe, related primarily to the initial recording of reserves at the Aseng oil project, 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, Alen, Tamar and Leviathan and from new discoveries resulting from our active exploration programs in the deepwater Gulf of Mexico and international locations. 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 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).

Table of Contents

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 ample liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long-cycle, multi-year, capital-intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives. We also utilize a commodity price hedging program to reduce commodity price uncertainty and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and operations.

Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under our credit facility. During 2011, we strengthened our liquidity position with two public debt offerings. Occasional sales of non-core crude oil and natural gas properties as well as our periodic access to debt and capital markets may also provide cash to support opportunities.

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.

Marcellus Shale Joint Venture   On September 30, 2011, we closed a joint venture arrangement with a subsidiary of CONSOL Energy, Inc. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

The transaction is structured in a unique way from a financial perspective. We have 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, at a minimum, over an eight-year period and is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices. These conditions allow us to integrate a new core area into our existing long range plan while maintaining our strong balance sheet and financial flexibility. We funded the initial cash payment with cash on hand and borrowings under our credit facility and expect to fund the remaining installment payments and CONSOL Carried Cost Obligation with cash on hand and our credit facility. Targeted divestments of non-core assets may also be a source of funding. At December 31, 2011 the CONSOL Carried Cost Obligation was suspended. See Off-Balance Sheet Arrangements below.

Information regarding cash and debt balances was as follows:

	December 31,		
	2011	2010	2009
(millions, except percentages)			
Cash and Cash Equivalents	$1,455	$1,081	$1,014
Amount Available to be Borrowed Under Credit Facility (1)	3,000	1,750	1,718
Total Liquidity	$4,455	$2,831	$2,732
Total Debt (2)	$4,495	$2,279	$2,045
Total Shareholders' Equity	7,265	6,848	6,157
Debt-to-Capital Ratio (3)	38 %	25 %	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 $1.5 billion in cash and cash equivalents at December 31, 2011, compared with approximately $1.1 billion at December 31, 2010. At December 31, 2011, our cash was primarily denominated in US dollars and was invested in money market funds and short-term deposits with major financial institutions. Almost $800 million 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 this cash during 2012 to fund international projects, including the development of our properties in West Africa and the Eastern Mediterranean.

Credit Facility On October 14, 2011, we entered into a Credit Agreement which provides for a new $3.0 billion unsecured revolving credit facility due October 14, 2016. The new credit facility replaced the previous credit facility of $2.1 billion due to mature December 9, 2012. See Financing Activities – New Credit Facility below.

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

Table of Contents

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, 2011 the fair value of our commodity derivative assets was $47 million and the fair value of our commodity derivative liabilities was $83 million (after consideration of netting 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.

Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments. None of our counterparty agreements currently contain margin requirements. However, 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.

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.

European Debt Crisis The debt crisis is ongoing and continues to have a negative impact on the European economy, with risks to the global banking system and overall global economy and financial system. Some of our commodity derivatives counterparties are international banks that are also lenders in our $3.0 billion New Credit Facility. These institutions could potentially be affected by the European debt crisis and be unable to participate in our drawdowns. We believe our current strong 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.

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. We are continuing to monitor the wellbore and there are no indications of any hydrocarbons in the produced water. 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 most of 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,

(millions)	2011	2010	2009
Total Cash Provided By (Used in)			
Operating Activities	$2,170	$1,946	$1,508
Investing Activities	(3,113)	(1,779)	(1,265)
Financing Activities	1,317	(100)	(369)
Increase (Decrease) in Cash and Cash Equivalents	$374	$67	$(126)

Operating Activities   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.

Net cash provided by operating activities in 2010 increased $438 million, or 29%, as compared with 2009. Sales revenues were higher due to increases in commodity prices and sales volumes. In addition, we received a refund of deepwater Gulf of Mexico royalties and higher dividends from equity method investees.

Investing Activities   The primary use of cash in investing activities is for capital spending, which may be offset by proceeds from property sales.

Capital spending, on a cash basis, totaled $3.2 billion in 2011, 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.

Table of Contents

Capital spending, on a cash basis, totaled $2.3 billion in 2010, including $458 million spent on the DJ Basin asset acquisition, representing an increase of $1.1 billion as compared with 2009. A significant portion of the spending was related to our major development projects. We received $564 million total proceeds from asset divestitures.

In 2009, our capital spending including acquisitions, totaled $1.3 billion. We received net proceeds from property sales of $3 million.

Financing Activities   Net cash provided by financing activities was $1.3 billion in 2011. 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).

In 2009, net cash of $369 million was used in financing activities. We received $989 million net proceeds from the issuance of our 8¼% senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($22 million). We made net repayments of amounts outstanding under our revolving credit facility ($1.2 billion), repaid an installment note ($25 million), and repurchased a portion of our 7¼% Senior Debentures due August 1, 2097 ($4 million). We also paid cash dividends on our common stock ($126 million) and repurchased shares of our common stock ($1 million).

Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition (1)	$982	$305	$92
Proved Property Acquisition (2)	392	352	-
Exploration	493	343	242
Development	2,200	1,520	881
Corporate and Other	196	121	102
Total	$4,263	$2,641	$1,317
Other			
Investment in Equity Method Investee (3)	$69	$-	$-
Increase in FPSO Lease Obligation (4)	66	266	29

(1) 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 Profound block), $31 million related to additional acreage in the DJ Basin, and $58 million related to miscellaneous 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. Unproved property acquisition cost for 2009 includes $56 million for deepwater Gulf of Mexico lease blocks and the remainder primarily for other onshore US lease acquisition.

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

(3) In connection with the Marcellus Shale Joint Venture, we acquired a 50% interest in CONE for $69 million in cash. CONE was formed for the purpose of owning and operating the existing gathering assets and constructing, owning and operating all of the additional gathering lines and related facilities that will be needed during the course of the Marcellus Shale development and will be accounted for using the equity method.

(4) Relates to estimated construction progress to date on an FSPO to be used in the development of the Aseng field, offshore Equatorial Guinea. The FPSO went into service during the fourth quarter of 2011.

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

Total expenditures in 2010 doubled as compared with 2009 due to major development project expenditures and the DJ Basin asset acquisition. In addition, seismic and dry hole expense increased.

Table of Contents

Asset Divestitures In 2011, we transferred our offshore Amistad field assets, onshore gas processing facilities, and Block 3 PSC, as well as the Machala Power electritcity concession and its associated 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 and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations or production facilities and other property and injury to persons. 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), 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.

For example, in certain international locations (including Israel and Equatorial Guinea) we carry business interruption insurance for loss of revenue 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 the Gulf of Mexico, we self-insure for windstorm exposure. Our Gulf of Mexico assets are primarily subsea operations; therefore, our 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 a result, we are responsible for substantially all windstorm-related damages to our Gulf of Mexico assets.

As is customary with industry practice, oil and 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, oil and gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $500 million of well control, pollution cleanup and consequential damages coverage and $326 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death. Consequently if we were to experience an accident similar to the Deepwater Horizon Incident, our total coverage for cleanup and consequential damages would cover a gross loss of at least $826 million depending on our ownership interest and subject to reduction for claims related to well control and third-party damages.

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 expect the future availability and cost of insurance to be impacted by the various catastrophic events in 2010 and 2011. 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.

During 2010, various Congressional committees began pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act may be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either a much higher level of insurance coverage than was standard for the industry in the past, or a financial position large enough that a company could settle its own damage claims. We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and other recent 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.

Deepwater drilling 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 the likelihood of a significant accident or spill is remote. However, if an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our financial condition, results of operations and cash flows. See Item 1A. Risk Factors – The insurance we carry is insufficient to cover all of the risks we face, which could result in significant financial exposure.

Table of Contents

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

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

Financing Activities

Long-Term Debt   Our long-term debt totaled $4.1 billion (excluding the Aseng FPSO lease obligation) at December 31, 2011, with maturities ranging from 2012 to 2097. Our principal source of liquidity is an unsecured revolving credit facility that matures October 14, 2016. Other than amounts drawn and repaid under our credit facility, we did not engage in any other short-term borrowing arrangements during 2010 or 2011.

New Credit Facility   On October 14, 2011, we entered into a Credit Agreement which provides for a new $3.0 billion unsecured revolving credit facility (the New Credit Facility). The New Credit Facility terminated and replaced our $2.1 billion credit facility maturing December 9, 2012.

The New Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (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.

At December 31, 2011, there were no borrowings outstanding under the credit facility, leaving $3.0 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 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 New Credit Facility and require the immediate repayment of any outstanding advances under the New Credit Facility.

The New 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   On September 30, 2011, we closed an agreement with CONSOL under which we agreed to purchase a 50% interest in undeveloped Marcellus Shale acreage. In addition to the cash paid at closing, we agreed to make two additional installment payments of $328 million each on September 30, 2012 and 2013. The installment payments have been discounted at our incremental borrowing rate, a weighted average of 1.76%. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

Public Debt Offerings   In order to provide increased liquidity and lengthen our weighted average debt maturity, we completed two public debt offerings during 2011. On February 18, 2011, we completed an underwritten public offering of $850 million of 6% senior unsecured notes due March 1, 2041, receiving net proceeds of $836 million after deducting discount and underwriting fees. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility maturing 2012 and the balance of the proceeds have been used to fund our exploration and development activities.

On December 8, 2011, we completed an underwritten public offering of $1.0 billion of 4.15% senior unsecured notes due December 15, 2021, receiving net proceeds of $992 million after deducting discount and underwriting fees. Approximately $400 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility and the balance of the proceeds will be used for general corporate purposes.

In 2009, we completed an underwritten public offering of $1.0 billion senior unsecured notes receiving net proceeds of $989 million, after deducting the discount and underwriting fees. We used substantially all of the net proceeds to repay outstanding indebtedness under our credit facility. The notes are due March 1, 2019, and pay interest semi-annually at 8¼%.

FPSO Lease Obligation   In 2009, we entered into an agreement with an unrelated offshore technology provider for the construction and lease of an FPSO to be used for development of the Aseng field, offshore Equatorial Guinea. We account for the lease agreement as a capital lease. Throughout the construction phase, we included both the Aseng FPSO asset and associated long-term obligation in our balance sheet, based upon the percentage of construction completed at the end of each reporting period. The obligation increased $66 million during 2011. The Aseng FPSO completed the construction phase and we commenced production at Aseng in November 2011. During 2011, we paid $3 million under our Aseng FPSO lease obligation.

Table of Contents

Fixed-Rate Debt Our outstanding fixed-rate debt, including the remaining CONSOL installment payments, totaled approximately $4.1 billion at December 31, 2011. The weighted average interest rate on fixed-rate debt was 5.56%, with maturities ranging from 2012 to 2097. Approximately 21% 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. In 2010, in anticipation of our March 2011 public debt offering, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on the anticipated debt issuance. The swap was in the notional amount of $500 million and was based on a 30-year LIBOR swap rate. Upon the issuance of our 6% senior unsecured notes due March 1, 2041, we settled our interest rate forward starting swap contract for $40 million in February 2011 and are amortizing remaining amounts from AOCL to interest expense over the term of the notes.

We previously entered into interest rate derivative instruments related to the issuance of 5¼% Senior Notes due April 2014 and are amortizing remaining amounts from AOCL to interest expense over the term 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 increased to 38% at December 31, 2011 from 25% at December 31, 2010. Significant changes in our financial position included the following:

- $2.2 billion increase in total principal amount of debt from the balance at December 31, 2010; and
- $143 million decrease in shareholders' equity from dividends paid;

offset by:

- $453 million increase in shareholders' equity from current year net income.

Cash Interest Payments We made cash interest payments of $164 million in 2011, $133 million in 2010, and $97 million in 2009.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $38 million in 2011, $47 million in 2010, and $17 million in 2009. 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 80 cents per common share in 2011, 72 cents per common share in 2010, and 72 cents per common share in 2009. On January 24, 2012, the Board of Directors declared a quarterly cash dividend of 22 cents per common share, which will be paid February 21, 2012 to shareholders of record on February 6, 2012. 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 187,000 shares with a total value of $17 million in 2011, 168,000 shares with a total value of $13 million in 2010 and 21,000 shares with a total value of $1 million in 2009.

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, 2011, 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 eight years or more. 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. Based on the December 31, 2011 Henry Hub natural gas strip, we forecast our CONSOL Carry Obligation will be suspended throughout the 2012 fiscal year and resume during first quarter of 2013.

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

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.

Table of Contents

Contractual Obligations

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

Obligation (millions)	Total	2012	2013 and 2014	2015 and 2016	2017 and beyond
Long-Term Debt (1)	$4,140	$328	$528	$-	$3,284
Interest Payments (2)	3,502	224	444	417	2,417
FPSO Lease Payments (3)	486	72	144	115	155
Drilling and Equipment Obligations (4)					
United States	220	110	97	13	-
International	109	109	-	-	-
Purchase Obligations (5)	778	761	17	-	-
Transportation and Gathering (6)	466	55	86	58	267
Operating Lease Obligations (7)	185	45	55	53	32
Other Liabilities (8)					
Asset Retirement Obligations (9)	377	33	38	28	278
Commodity Derivative Instruments (10)	83	76	7	-	-
Total Contractual Obligations	$10,346	$1,813	$1,416	$684	$6,433

(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, 2011. 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, and began during fourth quarter of 2011 once the Aseng FPSO initiated producing operations. 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. The table excludes the CONSOL Carried Cost Obligation noted above as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 21. 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 21. Commitments and Contingencies.

(6) Transportation and gathering obligations represent minimum charges for our firm transportation and gathering agreements. See Item 8. Financial Statements and Supplementary Data – Note 21. 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. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $222 million and accrued benefit costs of $88 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit 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, 2011. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2011. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

As of December 31, 2011, 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 $59 million at December 31, 2011.

Table of Contents

Other

Contributions to Pension and Other Postretirement Benefit Plans We made contributions to the pension and other postretirement benefit plans totaling $29 million in 2011, $24 million in 2010, and $21 million in 2009. The actual return on plan assets was a loss of $1 million in 2011, a gain of $23 million in 2010, and a gain of $33 million in 2009. The investment return has tended to follow market performance. Certain provisions of the Pension Protection Act of 2006 (the Act) changed the calculation related to the maximum contribution amount deductible for income tax purposes and required that defined benefit pension plans become fully funded over a seven-year period beginning in 2008. As a result of previous contributions made to the pension plan, the plan is adequately funded at the balance sheet date, and we expect the plan would not be subject to any of the benefit limitations that would be imposed by the Act if the plan were not adequately funded. We expect to make cash contributions of approximately $13 million to the pension plan during 2012. We expect to make contributions to the restoration and medical and life plans of approximately $4 million during 2012, an amount which is estimated to be equal to the benefits expected to be paid by those plans.

Income Taxes We made cash payments for income taxes, net of refunds, of $288 million in 2011, $173 million in 2010, and $227 million in 2009.

Contingencies Payments to settle legal proceedings totaled approximately $1 million in 2011, $7 million in 2010, and $19 million in 2009. 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 2011 when we decided not to pursue development of our Redrock exploratory well in the deepwater Gulf of Mexico due to the significant decline in natural gas prices. At December 31, 2011, the balance of property, plant and equipment included $696 million of suspended exploratory well costs, $378 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 bi-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 2011, 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 $759 million in 2011, $144 million in 2010 and $604 million in 2009 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.

Table of Contents

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, 2011, 2010 and 2009 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, 2011, the consolidated balance sheet included $696 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. During 2011, we adopted Accounting Standards Update (ASU) 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08). ASU 2011-08 permits an entity to first assess qualitative factors to determine whether is it more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. 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.

Table of Contents

After assessing the totality of events and circumstances for the qualitative impairment assessment at December 31, 2011, 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. No significant US dispositions requiring allocation of goodwill occurred during 2011. 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 payable position with a fair value of $36 million at December 31, 2011. 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.

Table of Contents

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, 2011, we reported a $42 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 16. 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 $377 million at December 31, 2011. 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. For example, during 2011 we increased our valuation allowance against our deferred tax asset for foreign tax credits by $57 million, of which $42 million offset a similar increase in the deferred tax asset and $15 million represented a net increase in deferred income tax expense.

Table of Contents

As of December 31, 2011, the accumulated undistributed earnings of our foreign subsidiaries on which no US taxes have been recorded totaled approximately $2.0 billion. 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.

In 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense a total of $13 million. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows due to the payment of additional taxes. We currently intend to use a majority 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 $800 million as of December 31, 2011, if we had elected not to use the cash to fund international development, would have had a net cash tax impact of approximately $121 million. This amount is net of estimated foreign tax credits. See Item 8. Financial Statements and Supplementary Data – Note 13. Income Taxes.

Allowance for Doubtful Accounts We assess the recoverability of all material trade and other receivables to determine their collectibility on a quarterly basis. 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. In determining the amount of the reserve, management must analyze the aging of accounts receivable at the date of the consolidated financial statements and assess collectability based on historic results, current collection trends and an evaluation of economic conditions. If estimates are inaccurate, we may incur gains or losses that could have a material effect on our results of operations.

During 2011, our allowance for doubtful accounts was reduced by approximately $19 million when we finalized our transfer of assets and the associated PSC and electricity concession to the Ecuadorian government. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Benefit Plans   We sponsor a qualified defined benefit pension plan, a non-qualified defined benefit pension plan (restoration plan), and other postretirement benefit plans. The actuarial determination of the projected benefit obligations and related benefit expense requires that management make certain assumptions regarding such variables as expected return on plan assets, discount rates, rates of future compensation increases, estimated future employee turnover rates and retirement dates, distribution election rates, mortality rates, inflation rates, spousal age differentials, marital trend rates, lump sum conversion rates, commencement ages for employees who vested in the plan but were terminated prior to retirement, retiree utilization rates for health care services and health care cost trend rates. The selection of assumptions requires considerable judgment concerning future events and has a significant impact on the amount of the obligations recorded in the consolidated balance sheets and on the amount of expense included in the consolidated statements of operations.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2012, cumulative asset losses of approximately $10 million remained to be recognized in the calculation of the market-related value of assets.

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds invested or to be invested to provide for plan benefits included in the projected benefit obligations. This includes considering the returns being earned by the plan assets and the rates of return expected to be available for reinvestment. During 2011, we changed the plan’s target asset allocation from 70% equity and 30% fixed income to 60% equity and 40% fixed income. The change was made to more closely align the plan’s expected future payment streams with the expected duration of plan liabilities. The change was also made to reduce the plan’s market risk and the degree of volatility in the plan’s investments. Because a larger portion of the plan’s funds are now invested in fixed income, which are considered to be less risky investments, the plan’s returns will likely be reduced in times of market upswings, while losses will be reduced in times of market downswings. We assume that the long-term asset mix will be consistent with the target asset allocation, with a range of plus or minus 10% acceptable degree of variation in asset allocation. The plan assets had a fair value of $220 million at December 31, 2011, and the expected return assumption used in the calculation of 2011 net periodic benefit cost was 7.25%. A 1% decrease in the expected return on plan assets assumption would have increased 2011 net periodic benefit cost by approximately $2 million. The expected return assumption will be reduced to 6.50% for the calculation of 2012 net periodic benefit cost.

In selecting a discount rate, employers may look to rates of return on high quality fixed-income investments available as of the year-end measurement date and expected to be available during the period to maturity of the pension benefits. In order to determine an appropriate December 31, 2011 discount rate, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) and various AA corporate bond yields for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high-quality, zero-coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans’ expected future benefit payment streams and duration of plan liabilities.

Table of Contents

A 1% increase in the discount rate assumption would have decreased 2011 net periodic benefit cost for the combined plans by $3 million and decreased the benefit obligation for the combined plans by $30 million at December 31, 2011. A 1% decrease in the discount rate assumption would have increased 2011 net periodic benefit cost for the combined plans by $2 million and increased the benefit obligation for the combined plans by $28 million at December 31, 2011. The assumed discount rate used to determine net periodic benefit cost for 2011 was 5.50% for the defined benefit pension plan, 5.25% for the restoration plan and 5.00% for the medical and life plan. The assumed discount rates used to determine the benefit obligations at December 31, 2011 were 4.25% for the defined benefit pension plan and the restoration plan and 4.00% for the medical and life plans. The total projected benefit obligation for the defined benefit pension, restoration and medical and life plans was $312 million at December 31, 2011. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit Plans.

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 uncertainty 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, 2011, we had entered into variable to fixed price commodity swaps, two-way and three-way collars and basis swaps related to future crude oil and natural gas sales. Our open commodity derivative instruments were in a net payable position with a fair value of $36 million. Based on the December 31, 2011 published forward commodity price curves, a price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative payable by approximately $18 million. A price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative payable by approximately $6 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 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, 2011, we had approximately $4.1 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 5.56%. 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 had no variable-rate debt outstanding at December 31, 2011. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates.

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, 2011, AOCL included $26 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 2014 and 6% senior notes due March 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, 2011, our cash and cash equivalents totaled almost $1.5 billion, approximately 84% of which was invested in money market funds and short-term deposits with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of December 31, 2011 would result in a change in annual interest income of approximately $3 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. An increase in exchange rates between the US dollar and the currency of the foreign tax jurisdiction in which these liabilities are located could result in the use of additional cash to settle these liabilities. Transaction gains or losses were not material in any of the periods presented and are included in other non-operating (income) expense, net in the consolidated statements of operations.

Table of Contents

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

Table of Contents

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, 2011, 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, 2011, 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, 2011 which is included herein.

Noble Energy, Inc.

Table of Contents

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, 2011 and 2010, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011. 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 did not audit the financial statements of the Alba Plant LLC (Alba) for the year ended December 31, 2009, the investment in which, as discussed in Note 8 of the consolidated financial statements, is accounted for by the equity method of accounting. The Company's equity in earnings of Alba was $66 million, for the year ended December 31, 2009. The financial statements of Alba were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Alba, is based solely on the report of the other auditors.

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, based on our audits and the report of the other auditors, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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, 2011, 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 9, 2012, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 9, 2012

Table of Contents

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, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 9, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 9, 2012

87

Table of Contents

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

	Year Ended December 31,		
	2011	2010	2009
Revenues			
Oil, Gas and NGL Sales	$3,536	$2,832	$2,060
Income from Equity Method Investees	195	118	84
Other Revenues	32	72	169
Total Revenues	3,763	3,022	2,313
Costs and Expenses			
Production Expense	618	570	525
Exploration Expense	279	245	144
Depreciation, Depletion and Amortization	965	883	816
General and Administrative	341	277	237
Gain on Divestitures	(25)	(113)	(22)
Asset Impairments	759	144	604
Other Operating Expense, Net	86	64	67
Total Operating Expenses	3,023	2,070	2,371
Operating Income (Loss)	740	952	(58)
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	(42)	(157)	110
Interest, Net of Amount Capitalized	65	72	84
Other Non-Operating (Income) Expense, Net	2	6	12
Total Other (Income) Expense	25	(79)	206
Income (Loss) Before Income Taxes	715	1,031	(264)
Income Tax Provision (Benefit)	262	306	(133)
Net Income (Loss)	$453	$725	$(131)
Earnings (Loss) Per Share, Basic	$2.57	$4.15	$(0.75)
Earnings (Loss) Per Share, Diluted	2.54	4.10	(0.75)
Weighted Average Number of Shares Outstanding, Basic	176	175	173
Weighted Average Number of Shares Outstanding, Diluted	179	177	173

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

Table of Contents

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

	Year Ended December 31,		
	2011	2010	2009
Net Income (Loss)	$453	$725	$(131)
Other Items of Comprehensive Income (Loss)			
Oil and Gas Cash Flow Hedges			
Realized Losses Reclassified Into Earnings	-	20	58
Less Tax Provision (Benefit)	-	(8)	(22)
Interest Rate Cash Flow Hedges			
Unrealized Change in Fair Value	23	(63)	-
Less Tax Provision (Benefit)	(8)	22	-
Net Change in Pension and Other	(17)	-	(2)
Less Tax Provision (Benefit)	6	-	1
Other Comprehensive Income (Loss)	4	(29)	35
Comprehensive Income (Loss)	$457	$696	$(96)

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

Table of Contents

Noble Energy, Inc.
Consolidated Balance Sheets
(in millions)

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,455	$1,081
Accounts Receivable, Net	783	556
Other Current Assets	180	201
Total Assets, Current	2,418	1,838
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	17,703	14,393
Property, Plant and Equipment, Other	294	263
Total Property, Plant and Equipment, Gross	17,997	14,656
Accumulated Depreciation, Depletion and Amortization	(5,215)	(4,392)
Total Property, Plant and Equipment, Net	12,782	10,264
Goodwill	696	696
Other Noncurrent Assets	548	484
Total Assets	$16,444	$13,282
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,343	$927
Other Current Liabilities	925	495
Total Liabilities, Current	2,268	1,422
Long-Term Debt	4,100	2,272
Deferred Income Taxes, Noncurrent	2,059	2,110
Other Noncurrent Liabilities	752	630
Total Liabilities	9,179	6,434
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3; 250 Million Shares Authorized; 197 Million and 195 Million Shares Issued, Respectively	656	651
Additional Paid in Capital	2,497	2,385
Accumulated Other Comprehensive Loss	(100)	(104)
Treasury Stock, at Cost; 19 Million Shares	(638)	(624)
Retained Earnings	4,850	4,540
Total Shareholders' Equity	7,265	6,848
Total Liabilities and Shareholders' Equity	$16,444	$13,282

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

Table of Contents

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

	Year Ended December 31,		
	2011	2010	2009
Cash Flows From Operating Activities			
Net Income (Loss)	$ 453	$ 725	$ (131)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	965	883	816
Dry Hole Expense	105	58	11
Gain on Divestitures	(25)	(113)	(22)
Asset Impairments	759	144	604
Deferred Income Taxes	(81)	71	(296)
Dividends (Income) from Equity Method Investees, Net	30	21	8
Unrealized (Gain) Loss on Commodity Derivative Instruments	22	(70)	606
Stock Based Compensation	58	54	49
Other Adjustments for Noncash Items Included in Income	40	15	10
Changes in Operating Assets and Liabilities			
(Increase) Decrease in Accounts Receivable	(244)	(86)	(28)
(Increase) Decrease in Other Current Assets	7	18	(4)
Increase (Decrease) in Accounts Payable	(2)	234	(19)
Increase (Decrease) in Other Current Liabilities	75	34	(38)
Other Operating Assets and Liabilities, Net	8	(42)	(58)
Net Cash Provided by Operating Activities	2,170	1,946	1,508
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(2,594)	(1,885)	(1,268)
Marcellus Shale Asset Acquisition	(527)	-	-
DJ Basin Asset Acquisition	-	(458)	-
Additions to Equity Method Investments	(69)	-	-
Proceeds from Divestitures	77	564	3
Net Cash Used in Investing Activities	(3,113)	(1,779)	(1,265)
Cash Flows From Financing Activities			
Exercise of Stock Options	38	47	17
Excess Tax Benefits from Stock-Based Awards	15	25	5
Dividends Paid, Common Stock	(143)	(127)	(126)
Purchase of Treasury Stock	(17)	(13)	(1)
Proceeds from Credit Facilities	520	760	340
Repayment of Credit Facilities	(870)	(792)	(1,564)
Proceeds from Issuance of Senior Long-Term Debt	1,828	-	989
Settlement of Interest Rate Derivative Instrument	(40)	-	-
Other	(14)	-	(29)
Net Cash Provided by (Used in) Financing Activities	1,317	(100)	(369)
Increase (Decrease) in Cash and Cash Equivalents	374	67	(126)
Cash and Cash Equivalents at Beginning of Period	1,081	1,014	1,140

Cash and Cash Equivalents at End of Period	$	1,455	$	1,081	$	1,014

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

Table of Contents

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

	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2008	$641	$2,193	$(110)	$(614)	$4,199	$6,309
Net Loss	-	-	-	-	(131)	(131)
Stock-based Compensation Expense	-	49	-	-	-	49
Exercise of Stock Options	2	15	-	-	-	17
Tax Benefits Related to Exercise of Stock Options	-	5	-	-	-	5
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Cash Dividends (72 cents per share)	-	-	-	-	(126)	(126)
Purchase of Treasury Stock	-	-	-	(1)	-	(1)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	36	-	-	36
Net Change in Other	-	-	(1)	-	-	(1)
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
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Cash Dividends (72 cents per share)	-	-	-	-	(127)	(127)
Purchase of Treasury Stock	-	-	-	(13)	-	(13)
	-	5	-	4	-	9

Rabbi Trust Shares Sold						
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	-	-	-	-	-	-
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
Restricted Stock Awards, Net	2	(2)	-	-	-	-
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	-	-	(11)	-	-	(11)
December 31, 2011	$656	$2,497	$(100)	$(638)	$4,850	$7,265

The accompanying notes are an integral part of these financial statements

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies

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

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to US GAAP. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. See Note 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 and goodwill, asset retirement obligations, valuation allowances for receivables and deferred income tax assets, valuation of derivative instruments, and obligations related to employee benefits, 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, including the further decline in US natural gas prices occurring in early 2012, 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 2010 and 2009 consolidated financial statements to conform to the 2011 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 16. 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 bi-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 2011, 2010, and 2009. It is likely that other proved oil and gas properties could become impaired in the future if commodity prices significantly 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 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.

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.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 $132 million in 2011, $67 million in 2010, and $45 million in 2009.

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 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 In September 2011, the FASB issued Accounting Standards Update No. 2011-08: Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment (ASU 2011-08). ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. Under ASU 2011-08, an entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount. ASU 2011-08 is effective for annual periods beginning after December 15, 2011, but early adoption is permitted. We adopted ASU 2011-08 as of December 31, 2011. The adoption of ASU 2011-08 did not have any impact on our financial position and results of operations as of December 31, 2011 as it is a change in application of the goodwill impairment test only.

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, 2011. However, it is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable. 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 netting arrangement.

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.

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, 2011 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. Benefit Plans.

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 15. Stock-Based Compensation.

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 17. 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 21. 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.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 were not material in any of the periods presented and 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 18. Segment Information.

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 U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on our financial position and results of operations.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05: Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. The update is intended to increase the prominence of other comprehensive income in the financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011.

In December 2011, the FASB issued Accounting Standards Update No. 2011-12: Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). The Update defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. As part of this update, the FASB did not defer the requirement to report comprehensive income either in a single continuous statement or in two separate but consecutive financial statements. ASU 2011-12 is effective for annual periods beginning after December 15, 2011.

As of December 31, 2011, we early adopted the provisions of ASU 2011-05 requiring presentation of comprehensive income in two consecutive financial statements.

As of December 31, 2011, we early adopted the provisions of ASU 2011-08. See Goodwill, above.

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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Other Revenues			
Electricity Sales (1)	$32	$73	$72
Refund of Deepwater Gulf of Mexico Royalties (2)	-	-	86
Other	-	(1)	11
Total	$32	$72	$169
Production Expense			
Lease Operating Expense	$397	$376	$372
Production and Ad Valorem Taxes	146	125	94
Transportation Expense	75	69	59
Total	$618	$570	$525
Other Operating Expense, Net			
Deepwater Gulf of Mexico Moratorium Expense (3)	$18	$27	$-
Electricity Generation Expense (1)	26	39	18
Write-down of SemCrude L.P. Receivable (4)	-	-	12
Loss on Involuntary Conversion (5)	4	-	-
Other, Net	38	(2)	37
Total	$86	$64	$67
Other Non-Operating (Income) Expense, Net			
Deferred Compensation Expense (6)	$8	$15	$23
Interest Income (7)	(8)	(7)	(13)
Other (Income) Expense, Net	2	(2)	2
Total	$2	$6	$12

(1) Amount represents electricity sales from the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including DD&A and changes in the allowance for doubtful accounts. See Note 3. Acquisitions and Divestitures, Note 4. Asset Impairments, and Note 5. Allowance for Doubtful Accounts.

(2) The refund was attributable to royalties that we previously paid on crude oil and natural gas produced in the deepwater Gulf of Mexico from January 1, 2003 through July 31, 2009.

(3) Amounts relate to rig stand-by expense incurred prior to receiving a permit to resume drilling activities in the deepwater Gulf of Mexico in 2011 and costs to terminate a deepwater Gulf of Mexico drilling rig contract due to the deepwater Gulf of Mexico drilling moratorium in 2010.

(4) See Note 5. Allowance for Doubtful Accounts.

(5) The loss on involuntary conversion represents our insurance deductible related to the Leviathan-2 appraisal well control incident. We suspended operations on the Leviathan-2 well, offshore Israel, in May 2011 when we

identified water flowing to the sea floor from the wellbore. The incident was a covered event under our well control insurance. At this time, we expect to recover most of the costs from insurance, subject to a deductible. The final amount to be recovered will be based on the cost to drill the Leviathan-3 replacement well down to the same depth at which the incident occurred, possible remediation activities and/or abandonment activities at the Leviathan-2 well, which have not yet been determined, and other factors. See footnote (2) below.

(6) Amount represents increases in the fair value of shares of our common stock held in a rabbi trust. See Note 14. Benefit Plans.

(7) Interest income for 2010 and 2009 includes $3 million and $11 million, respectively, related to the refund of deepwater Gulf of Mexico royalties.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Additional balance sheet information is as follows:

	December 31, 2011	December 31, 2010
(millions)		
Accounts Receivable, Net		
Commodity Sales	$356	$291
Joint Interest Billings	313	259
Other	123	33
Allowance for Doubtful Accounts (1)	(9)	(27)
Total	$783	$556
Other Current Assets		
Inventories, Current	$78	$112
Commodity Derivative Assets, Current	10	62
Deferred Income Taxes, Net, Current	41	9
Probable Insurance Claims (2)	15	-
Prepaid Expenses and Other Assets, Current	36	18
Total	$180	$201
Other Noncurrent Assets		
Equity Method Investments (3)	$329	$285
Mutual Fund Investments	99	112
Commodity Derivative Assets, Noncurrent	37	-
Other Assets, Noncurrent	83	87
Total	$548	$484
Other Current Liabilities		
Production and Ad Valorem Taxes	$121	$110
Commodity Derivative Liabilities, Current	76	24
Interest Rate Derivative Liability, Current	-	63
Income Taxes Payable	127	90
Asset Retirement Obligations, Current (4)	33	45
Interest Payable	56	36
CONSOL Installment Payment, Net (5)	324	-
Current Portion of FPSO Lease Obligation	45	-
Other Liabilities, Current	143	127
Total	$925	$495
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$222	$229
Asset Retirement Obligations, Noncurrent (4)	344	208
Accrued Benefit Costs, Noncurrent	88	76
Commodity Derivative Liabilities, Noncurrent	7	51
Other Liabilities, Noncurrent	91	66
Total	$752	$630

(1) The decrease in the allowance for doubtful accounts from December 31, 2010 is due primarily to the transfer of assets to the Ecuadorian government. See Note 3. Acquisitions and Divestitures and Note 5. Allowance for Doubtful Accounts.

(2) Amount represents the costs incurred to date, net of insurance deductible and cash receipts for the Leviathan-2 appraisal well. See footnote (5) above.
(3) The increase in equity method investments from December 31, 2010 is due primarily to our acquisition of a 50% interest in CONE. See Note 3. Acquisitions and Divestitures.
(4) See Note 11. Asset Retirement Obligations.
(5) See Note 3. Acquisitions and Divestitures and Note 12. Long-Term Debt.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$32	$66	$52
Income Taxes Paid, Net	288	173	227
Non-Cash Financing and Investing Activities			
Increase in CONSOL Installment Payments, Net of Discount (1)	639	-	-
Increase in FPSO Lease Obligation (1)	66	266	29

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

Note 3. Acquisitions and Divestitures

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 50% interests in approximately 628,000 net undeveloped acres, certain producing properties, and existing infrastructure 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 $596 million to date, and, other than post-closing adjustments, the remainder will be paid in two annual installments. See Note 8. Equity Method Investments and 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, up to approximately $2.1 billion (CONSOL Carried Cost Obligation). The CONSOL Carried Cost Obligation is expected to extend over approximately eight years or more. The CONSOL Carried Cost Obligation is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The carry terms ensure economic alignment with our partner in periods of low natural gas prices. Amounts paid pursuant to the CONSOL Carried Cost Obligation will be recorded as increases in property, plant and equipment in our consolidated balance sheets and as investing activities in our consolidated statements of cash flows. See Note 21. Commitments and Contingencies.

In connection with the joint venture transaction and formation of CONE, we recorded the following:

	December 31, 2011
(millions)	
Unproved Oil and Gas Properties	$853
Proved Oil and Gas Properties	386
Initial Investment in CONE Gathering LLC	69
Total Assets Acquired (1)	$1,308

(1) Total reflects impact of discount on CONSOL installment payments.

To estimate the fair value of the proved oil and gas properties as of the acquisition date, we used an income approach. 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. See, Note 16. Fair Value Measurements and Disclosures.

Certain data necessary to complete the final purchase price allocation for proved oil and gas properties is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed. We expect to complete the final purchase price allocation during the 12-month period following the acquisition date, during which time the preliminary allocation may be revised.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Gas Gathering Agreement with CONE In connection with the Marcellus Shale Joint Venture described above, we entered into a 50-year gathering and marketing agreement with CONE. Under the terms of the gathering and marketing agreement, we will pay CONE a minimum annual revenue commitment (MARC). The MARC will be adjusted annually based on projected gathering volumes, operating expenses, capital expenditures, and other factors. For fiscal year 2011, the MARC totaled approximately $3 million. See Note 21. Commitments and Contingencies.

We also have agreed to fund an annual work program for the construction of additional pipeline assets to receive and deliver production from future wells. Amounts to be contributed in future years to fund our proportionate share of the annual work program will be dependent upon anticipated production locations, volumes and other factors. We account for our 50% interest in CONE using the equity method; therefore, our share of income is reported as income from equity method investees in our consolidated statements of operations. Our investment in CONE is reported as investment in equity method investee in our consolidated balance sheets and reflects our cash contributions to the entity. See Note 8. Equity Method Investments.

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:

(millions)	December 31, 2010
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:

(millions)	Year Ended December 31, 2010
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

Table of Contents

Note 4. Asset Impairments

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

Noble Energy, Inc.
Notes to Consolidated Financial Statements

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Piceance (Onshore US)	$487	$-	$-
Tri-State (Onshore US)	121	-	-
Iron Horse (Onshore US)	15	89	-
East Texas (Onshore US)	128	-	-
New Albany Shale (Onshore US)	-	19	44
Granite Wash (Onshore US)	-	-	389
Main Pass (Gulf of Mexico Shelf)	-	5	48
Raton (Deepwater Gulf of Mexico)	-	6	23
Noa/Noa South (Offshore Israel)	-	25	-
Ecuador	-	-	100
Other Onshore US Proved Properties	6	-	-
Other Offshore International Proved Properties	2	-	-
Total	$759	$144	$604

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. The discounted cash flow models included management's estimates of future oil and gas production, commodity prices based on forward commodity price curves as of the date of the estimate, operating and development costs, and discount rates.

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.

2009 Asset Impairments Declines in natural gas prices resulted in impairments of Granite Wash, an onshore US area where we significantly reduced our investment beginning in 2007, and our New Albany Shale development. We also impaired our deepwater Gulf of Mexico development at Raton, primarily due to well performance issues and our Gulf of Mexico shelf asset at Main Pass, which had been reclassified from held-for-sale to held-and-used. The assets were written down to their estimated fair values, which were determined using discounted cash flow models, as described above.

We also reviewed our investment in Ecuador for impairment, as a result of the increasingly unsettled economic and political environment in Ecuador, and determined that the carrying value of our investment exceeded its fair value. We estimated the fair value of our investment using a probability-weighted discounted cash flow model that considered the likelihood of possible outcomes of (1) the event of continued operation of the assets in contemplation of resolving the dispute and in accordance with the existing contract, (2) the event of a sale of our investment to a third party, and (3) the event of arbitration with varying degrees of award and collection. The use of alternative judgments and/or assumptions could have resulted in the recognition of an impairment charge that was significantly different.

See also Note 16. Fair Value Measurements and Disclosures.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 5. Allowance for Doubtful Accounts

Changes in the allowance for doubtful accounts were as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Balance, Beginning of Period	$27	$31	$97
Changes			
Allowance for Ecuador Receivable	-	1	14
Recovery of Ecuador Receivable (1)	(19)	(7)	(46)
Allowance for SemCrude L.P. Receivable	-	-	12
Other Changes	1	2	2
Net Changes Before Write-offs	(18)	(4)	(18)
Write-off of SemCrude L.P. Receivable (2)	-	-	(49)
Other Write-offs	-	-	1
Balance, End of Period	$9	$27	$31

(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. Amount in 2009 was received in accordance with the terms of a settlement agreement and included as a reduction in electricity generation expense.

(2)SemCrude, L.P. was a crude oil purchaser who filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in 2008.

Note 6. Inventories

Inventories consisted of the following:

	December 31,	
	2011	2010
(millions)		
Materials and Supplies	$56	$95
Crude Oil	22	17
Total	$78	$112

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.

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,		
	2011	2010	2009
(millions)			
Capitalized Exploratory Well Costs, Beginning of Period	$466	$463	$522
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	322	161	153
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(55)	(155)	(205)
Capitalized Exploratory Well Costs Charged to Expense	(37)	(3)	(7)
Capitalized Exploratory Well Costs, End of Period	$696	$466	$463

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

The following table provides an aging of capitalized exploratory well costs (suspended well costs) based on the date that drilling commenced and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the commencement of drilling:

	December 31,		
	2011	2010	2009
(millions)			
Exploratory Well Costs Capitalized for a Period of One Year or Less	$318	$166	$175
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	378	300	288
Balance at End of Period	$696	$466	$463
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	9	9	5

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, 2011:

		Suspended Since		
	Total	2010	2009	2008 & Prior
(millions)				
Country/Project				
Offshore Equatorial Guinea				
Blocks O and I	$112	$6	$19	$87
Offshore Cameroon				
YoYo	40	2	2	36
Offshore Israel				
Leviathan	41	41	-	-
Dalit	22	1	21	-
Deepwater Gulf of Mexico				
Gunflint	59	3	6	50
Deep Blue	73	54	19	-
North Sea				
Selkirk	23	1	1	21
Other				
2 projects of $10 million or less each	8	8	-	-
Total	$378	$116	$68	$194

Blocks O and I   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries. During the second quarter of 2011, we drilled the successful Diega appraisal well which encountered both crude oil and natural gas. We have drilled two sidetracks, each of which encountered hydrocarbons. We are currently finalizing our appraisal of Diega and are evaluating regional development scenarios.

YoYo   YoYo is a 2007 natural gas and condensate discovery. During 2011 we acquired and processed additional 3-D seismic information and are evaluating for future drilling potential.

Leviathan Leviathan is a 2010 natural gas discovery. We are continuing to evaluate the discovery with the successful drilling of the Leviathan-3 appraisal well. In January 2012, we resumed drilling at the Leviathan-1 well in order to evaluate two additional intervals for the existence of crude oil. Results from these deeper tests are expected during the first half 2012. We will require an additional one or two appraisal wells to further define Leviathan’s boundaries in order to determine the best development option including subsea tieback to existing shallow water platform, semi-submersible platform, FPSO, or floating LNG.

Dalit Dalit is a 2009 natural gas discovery. We are currently working with our partners on a cost-effective development plan.

Gunflint Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. Our plans to drill two or three appraisal wells in 2011 were delayed by the post-Deepwater Moratorium permitting process. In October 2011, we received a drilling permit and in December 2011 we resumed drilling at Gunflint. We currently anticipate drilling up to three appraisal wells to fully evaluate the extent of the reservoir. We are also reviewing host platform options including: subsea tieback to an existing third-party host and construction of a new facility. If we are able to connect to an existing third-party host, the project could have an accelerated completion schedule, thereby potentially absorbing time lost due to the drilling delay caused by the Deepwater Moratorium and permit-related delay.

Deep Blue Deep Blue (Green Canyon Block 723) was a significant test well, which began drilling during 2009. When the Deepwater Moratorium was announced in May 2010, we were required to suspend side track drilling activities at the Deep Blue prospect. In November 2011 we announced that we have finished the well and found additional hydrocarbons in high quality reservoirs. During first quarter of 2012, we will be completing additional analysis of the data from the side track well.

Selkirk The Selkirk project is located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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, 2011, our retained earnings included $106 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $14 million higher than the underlying net assets of the investee at December 31, 2011. The difference includes $10 million relating to capitalized interest which is being amortized into earnings over the remaining useful life of the plant. The remaining $4 million relates to a note receivable from our funding a portion of the local government's share of the plant's development. The note receivable is being recovered through distributions from AMPCO.

Equity method investments are as follows:

	December 31,	
	2011	2010
(millions)		
Equity Method Investments		
AMPCO	$147	$166
Alba Plant	96	107
CONE	72	-
Other	14	12
Total Equity Method Investments	$329	$285

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

	December 31,	
	2011	2010
(millions)		
Balance Sheet Information		
Current Assets	$374	$307
Noncurrent Assets	827	735
Current Liabilities	360	265

Noncurrent Liabilities		16	16

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Statements of Operations Information			
Operating Revenues	$1,139	$809	$632
Operating Expenses	335	296	264
Operating Income	804	513	368
Other (Income) Net	(12)	(12)	(13)
Income Before Income Taxes	816	525	381
Income Tax Provision	201	133	95
Net Income	$615	$392	$286

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 9. Goodwill

Changes in the carrying amount of goodwill were as follows:

	Year Ended December 31,	
	2011	2010
(millions)		
Goodwill, Beginning Balance	$696	$758
Amount Allocated to Sale of Business Unit (1)	-	(61)
Other	-	(1)
Goodwill, Ending Balance	$696	$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 uncertainty 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 have also entered into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 16. 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 highly rated 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 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. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million. 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.   See Note 12. Long-Term Debt.

Unsettled Derivative Instruments   As of December 31, 2011, we have entered into the following crude oil derivative instruments:

				Swaps		Collars	
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
2012	Swaps	NYMEX WTI	5,000	$91.84	$-	$-	$-
2012	Swaps	Dated Brent	8,000	89.06	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	23,000	-	82.61	100.32	127.62
2014	Three-Way Collars	Dated Brent	5,000	-	80.00	92.00	130.50
Instruments entered into during January 1-31, 2012							
2013	Three-Way Collars	Dated Brent	5,000	-	90.00	105.00	127.97

As of December 31, 2011, we have entered into the following natural gas derivative instruments:

Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
2012	Swaps	NYMEX HH	30,000	$5.10	$-	$-	$-
2012	Two-Way Collars	NYMEX HH	40,000	-	-	3.25	5.14
2012	Three-Way Collars	NYMEX HH	110,000	-	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
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

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

As of December 31, 2011, we have entered into the following natural gas basis swaps:

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2012	IFERC CIG (1)	NYMEX HH	150,000	$(0.52)

(1) Colorado Interstate Gas – Northern System

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 December 31,				Liability Derivative Instruments December 31,			
	2011		2010		2011		2010	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 10	Current Assets	$ 62	Current Liabilities	$ 76	Current Liabilities	$ 24
	Noncurrent Assets	37	Noncurrent Assets	-	Noncurrent Liabilities	7	Noncurrent Liabilities	51
Interest Rate Derivative Instrument (Designated as Hedging Instrument)	Current Assets	-	Current Assets	-	Current Liabilities	-	Current Liabilities	63
	Total	$ 47	Total	$ 62	Total	$ 83	Total	$ 138

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

Commodity Derivative Instruments Not Designated as Hedging Instruments

Amount of (Gain) Loss on Derivative Instruments Recognized in Income

	Year Ended December 31,		
(millions)	2011	2010	2009

Realized Mark-to-Market (Gain)	$(64)	$(87)	$(496)
Unrealized Mark-to-Market (Gain) Loss	22	(70)	606
Total (Gain) Loss on Commodity Derivative Instruments	$(42)	$(157)	$110

Derivative Instruments in Cash Flow Hedging 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 Loss		
	2011	2010	2009	2011	2010	2009
(millions)						
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)						
Crude Oil	$-	$-	$-	$-	$19	$58
Natural Gas	-	-	-	-	1	-
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	(23)	63	-	1	1	1
Total	$(23)	$63	$-	$1	$21	$59

(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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

AOCL – Interest Rate Derivative Instruments At December 31, 2011, AOCL included deferred losses of $26 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

Changes in asset retirement obligations were as follows:

	Year Ended December 31, 2011	2010
(millions)		
Asset Retirement Obligations, Beginning Balance	$253	$232
Liabilities Incurred	23	17
Liabilities Settled	(24)	(56)
Revision of Estimate	105	43
Accretion Expense	20	17
Asset Retirement Obligations, Ending Balance	$377	$253

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 related to deepwater and shelf properties in the Gulf of Mexico. Revisions resulted from changes in estimated abandonment costs mainly in the DJ Basin and deepwater Gulf of Mexico.

For the year ended December 31, 2010, liabilities incurred were primarily due to the DJ Basin asset acquisition. Liabilities settled related to non-core onshore US properties sold, abandoned Gulf of Mexico shelf assets, and Block 3 offshore Ecuador. Revisions resulted from changes in estimated timing of actual abandonment due to shortened field lives for certain UK assets and overall cost increases for assets located primarily in the 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, 2011		December 31, 2010	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility, due December 9, 2012 (Old Credit Facility)	$-	-	$350	0.57 %
Credit Facility, due October 14, 2016 (New Credit Facility)	-	-	-	-
CONSOL Installment Payments, due September 30, 2012 and 2013	656	1.76 %	-	-

FPSO Lease Obligation (1)	355	-		295	-	
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	%	-	-	
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	%	-	-	
7¼% Senior Debentures, due August 1, 2097	84	7.25	%	84	7.25	%
Total	4,495			2,279		
Unamortized Discount	(26)			(7)		
Total Debt, Net of Discount	4,469			2,272		
Less Amounts Due Within One Year						
CONSOL Installment Payment, due September 30, 2012, net of discount	(324)			-		
FPSO Lease Obligation	(45)			-		
Long-Term Debt Due After One Year	$4,100			$2,272		

(1) Amount reported at December 31, 2010 was based on percentage of Aseng FPSO construction activities completed as of December 31, 2010. Amounts do not reflect future minimum lease payments. See Aseng FPSO Lease Obligation below.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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.

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 will be used for general corporate purposes.

New Credit Facility   On October 14, 2011, we entered into a credit agreement with certain commercial lending institutions (the Credit Agreement) which provides for a new $3.0 billion unsecured five-year revolving credit facility (the New Credit Facility). The New Credit Facility replaces our $2.1 billion credit facility maturing December 9, 2012. Also on October 14, 2011, we borrowed $400 million under the New Credit Facility, which was used to repay outstanding borrowings under and to terminate the $2.1 billion credit facility. Other than amounts drawn and repaid under our credit facility, we did not engage in any other short-term borrowing arrangements during 2010 or 2011.

The New Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (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 New Credit Facility and require the immediate repayment of any outstanding advances under the New Credit Facility. As of December 31, 2011, we were in compliance with our debt covenants.

The New 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.

Old Credit Facility   Our previous bank revolving credit facility (the Old Credit Facility), which was in place as of December 31, 2010 and 2009, was committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduced to $1.8 billion. The Old Credit Facility (i) provided for credit facility fee rates that ranged from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) made available short-term loans up to an aggregate amount of $300 million within the current $2.1 billion commitment and (iii) provided for interest rates that were based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the Old Credit Facility. The Old Credit Facility required that our total debt to capitalization ratio (as defined in the credit agreement), expressed as a percentage, not exceed 60% at any time. A violation of this covenant would have resulted in a default under the Old Credit Facility, which would have permitted the participating banks to restrict our ability to access the Old Credit Facility and require the immediate repayment of any outstanding advances under the Old Credit Facility. As of December 31, 2010, we were in compliance with our debt covenants. The Old Credit Facility was with certain commercial lending institutions and was available for general corporate purposes.

Certain lenders that were a party to the Old Credit Facility have in the past performed investment banking, financial advisory, lending or commercial banking services for us, for which they have received customary compensation and reimbursement of expenses.

The Old Credit Facility did not restrict the payment of dividends on our common stock, except, if after giving effect thereto, an Event of Default had occurred and be continuing or been caused thereby.

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 on September 30, 2012 and 2013. The installment payments have been discounted at the prevailing market rates for similar debt instruments. See Note 3. Acquisitions and Divestitures and Note 16. Fair Value Measurements and Disclosures.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Aseng FPSO Lease Obligation   We have entered into an agreement to lease a FPSO to be used in the development of 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, as of December 31, 2010, the percentage of construction activities completed, 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 as lease payments begin. In November 2011, production commenced and lease payments began. See Note 21. Commitments and Contingencies for future Aseng FPSO lease payments.

2009 Debt Offering   In 2009, we closed an offering of $1.0 billion senior unsecured notes receiving net proceeds of $989 million, after deducting the discount and underwriting fees. The notes are due March 1, 2019, and pay interest semi-annually at 8¼%. Debt issuance costs of approximately $2 million were incurred and are being amortized to expense over the life of the debt issue. Substantially all of the net proceeds from the offering were used to repay outstanding indebtedness under our revolving credit facility maturing 2012.

2009 Debt Repurchase   In 2009, we repurchased $5 million of our Senior Debentures due August 1, 2097, recognizing a debt extinguishment gain of $1 million.

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

(millions)	Debt Principal Payments
December 31, 2011	
2012	$ 328
2013	328
2014	200
2015	-
2016	-
Thereafter	3,284
Total	$ 4,140

Note 13. Income Taxes

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

	Year Ended December 31,		
(millions)	2011	2010	2009
Domestic	$(537)	$235	$(808)
Foreign	1,252	796	544
Total	$715	$1,031	$(264)

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

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Current Taxes			
Federal	$11	$25	$45
State	2	2	1
Foreign	330	208	117
Total Current	343	235	163
Deferred Taxes			
Federal	(130)	86	(320)
State	(3)	1	(5)
Foreign	52	(16)	29
Total Deferred	(81)	71	(296)
Total Income Tax Provision (Benefit)	$262	$306	$(133)
Effective Tax Rate	37%	30%	50%

111

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2011	2010	2009
(percentages)			
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	(9.3)	(4.0)	11.3
State Taxes, Net of Federal Benefit	(0.1)	0.3	1.5
Difference Between US and Foreign Rates	2.1	1.7	(1.4)
Percentage Depletion in Excess of Basis	(0.6)	(1.6)	4.5
Change in Valuation Allowance	4.6	(2.2)	1.5
Oil Profits Tax - Israel	2.5	-	-
Statutory Rate Change - UK	4.8	-	-
Other, Net	(2.4)	0.5	(2.0)
Effective Rate	36.6	29.7	50.4

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2011	2010
(millions)		
Deferred Tax Assets		
Loss Carryforwards	$66	$72
Ecuador Investment	-	12
Accrued Expenses	11	10
Allowance for Doubtful Accounts	-	5
Net Pension Obligation	42	35
Postretirement Benefits	36	35
Deferred Compensation	86	94
Foreign Tax Credits	57	25
Commodity Derivative Assets	37	38
Other	39	32
Total Deferred Tax Assets	374	358
Valuation Allowance - Foreign Loss Carryforwards	(65)	(58)
Valuation Allowance - Foreign Tax Credits	(57)	-
Valuation Allowance - Ecuador Investment	-	(12)
Net Deferred Tax Assets	252	288
Deferred Tax Liabilities		
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,276)	(2,389)
Total Deferred Tax Liability	(2,276)	(2,389)
Net Deferred Tax Liability	$(2,024)	$(2,101)

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

	December 31,	
(millions)	2011	2010
Deferred Income Tax Asset - Current	$41	$9
Deferred Income Tax Liability - Current	(6)	-
Deferred Income Tax Liability - Noncurrent	(2,059)	(2,110)
Net Deferred Tax Liability	$(2,024)	$(2,101)

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, 2011. 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.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Deferred tax assets associated with foreign loss carryforwards totaled $47 million in 2009, $70 million in 2010, and $65 million in 2011. Losses continue to be incurred on our project in Cameroon and other new venture activities which are not yet commercial.

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 is now fully offset by a valuation allowance because, based on our forecast of foreign tax credits, we do not believe it is more likely than not that the asset will 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 2011 as compared with 2010. This was primarily due to the changes in Israeli and UK tax law discussed below. Partially offsetting this increase was the impact of higher earnings from equity method subsidiaries in 2011, which has the effect of decreasing the rate when we have pre-tax income. 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.

Our effective tax rate decreased in 2010 as compared with 2009. For 2010, the effective rate was lower than the federal statutory rate because our income from equity method investees and other permanent differences have the impact of decreasing the effective rate when we have pre-tax income. The reversal of a $28 million deferred tax asset valuation allowance, discussed above, also reduced income tax expense.

Changes in Israeli Tax Law   In March 2011, the Israeli government enacted the Oil 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.

Changes in UK Tax Law The Finance Bill 2011, which became law on July 19, 2011, increased the rate of the Supplementary Charge levied on oil and gas income in the UK from 20% to 32% effective March 24, 2011. This change increased the tax rate on our UK oil and gas income from 50% to 62% and our 2011 consolidated effective income tax rate by approximately 7%. The change also resulted in a remeasurement of our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. As a result of the enactment, we recorded a $34 million increase in both our deferred income tax liability and deferred income tax expense during 2011.

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2011, the accumulated undistributed earnings of the foreign subsidiaries on which no US taxes have been recorded were approximately $2.0 billion. 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 $329 million.

During 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense by $13 million, of which $9 million was recorded in 2008. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

Unrecognized Tax Benefits   We did not have significant unrecognized tax benefits resulting from differences between positions taken in tax returns and amounts recognized in the financial statements as of December 31, 2011 or 2010. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. However, we did not accrue interest or penalties at December 31, 2011 or 2010, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax and we believe that we are below the minimum statutory threshold for imposition of penalties. We do not expect that the total amount of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Years Open to Examination   In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2008, Equatorial Guinea – 2007, Israel – 2008, UK – 2007, the Netherlands – 2009, and China – 2006.

Note 14. Benefit Plans

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. The benefits are based on an employee’s years of service and average earnings for the 60 consecutive calendar months of highest compensation. Our funding policy has been to make annual contributions equal to at least the minimum required contribution, but no greater than the maximum deductible for federal income tax purposes. We also have 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 for the benefit of our employees and retirees, which include medical and life insurance benefits. We use a December 31 measurement date for the plans.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Changes in the benefit obligation and plan assets of the pension, restoration and other postretirement benefit plans were as follows at December 31:

	Retirement and Restoration Plans		Medical and Life Plans	
	2011	2010	2011	2010
(millions)				
Change in Benefit Obligation				
Benefit Obligation, Beginning Balance	$262	$228	$24	$23
Service Cost	14	14	2	2
Interest Cost	13	13	1	1
Employee Contributions	-	-	1	1
Benefits Paid	(13)	(12)	(2)	(1)
Plan Amendments (1)	-	-	(6)	-
Actuarial Net (Gains) Losses	17	19	(2)	(2)
Benefit Obligation, Ending Balance	293	262	18	24
Change in Plan Assets				
Fair Value of Plan Assets, Beginning Balance	206	172	-	-
Actual Return on Plan Assets	(1)	23	-	-
Employer/Employee Contributions	27	23	2	1
Benefits Paid	(13)	(12)	(2)	(1)
Fair Value of Plan Assets, Ending Balance	219	206	-	-
Funded Status of Plan				
Funded Status at End of Year	(74)	(56)	(18)	(24)
Net Amount Recognized in Consolidated Balance Sheets	(74)	(56)	(18)	(24)
Amounts Recognized in Consolidated Balance Sheets Consist of				
Current Liabilities	(3)	(3)	(1)	(1)
Noncurrent Liabilities	(71)	(53)	(17)	(23)
Net Amount Recognized in Consolidated Balance Sheets	(74)	(56)	(18)	(24)
Amounts Not Yet Reflected in Net Periodic Benefit Cost and Included in AOCL				
Net Prior Service (Cost) Credit, Before Tax	(2)	(3)	10	6
Net Gains (Losses), Before Tax	(120)	(93)	(6)	(9)
AOCL	(122)	(96)	4	(3)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	48	40	(22)	(21)
Net Amount Recognized in Consolidated Balance Sheets	$(74)	$(56)	$(18)	$(24)

(1) Plan amendments relate to an increase in the monthly retiree contributions, changes to annual deductible, co-pays and annual out-of-pocket limit and change to reflect trend on retiree contributions for the medical and life plan.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Net periodic benefit cost recognized for the pension, restoration and other postretirement benefit plans was as follows:

	Retirement and Restoration Plans Year Ended December 31,			Medical and Life Plans Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
(millions)						
Components of Net Periodic Benefit Cost						
Service Cost	$14	$14	$12	$2	$2	$2
Interest Cost	13	13	11	1	1	1
Expected Return on Plan Assets	(15)	(14)	(14)	-	-	-
Amortization of Prior Service (Credit) Cost	-	-	-	(1)	(1)	(1)
Amortization of Net Loss and Other	6	5	3	1	1	1
Net Periodic Benefit Cost	$18	$18	$12	$3	$3	$3
Other Changes Recognized in AOCL						
Prior Service Cost Arising During Period	$-	$-	$-	$(6)	$-	$(2)
Net Loss (Gain) Arising During Period	33	10	5	(2)	(2)	1
Amortization of Prior Service Credit	-	-	-	1	1	1
Amortization of Net Loss	(6)	(5)	(3)	(1)	(1)	(1)
Total Recognized in AOCL	$27	$5	$2	$(8)	$(2)	$(1)
Expected Amortizations for Next Fiscal Year						
Amortization of Net Prior Service Cost (Credit)	$-	$-	$-	$(2)	$(1)	$(1)
Amortization of Net Losses	11	6	5	-	-	1
Weighted-Average Assumptions Used to Determine Benefit Obligations						
Discount Rate (1)	4.25%	5.50% / 5.25%	6.00%	4.00%	5.00%	5.50%
Rate of Compensation Increase (2)	4.00% - 13.00%	5.00%	5.00%	-	-	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs						
Discount Rate (3)	5.50% / 5.25%	6.00%	6.00% / 6.25%	5.00%	5.50%	6.25%

Expected Long-Term Return on Assets	7.25	%	7.50	%	8.00	%	-	-	-
Rate of Compensation Increase	5.00	%	5.00	%	5.00	%	-	-	-

(1) The discount rates used to determine benefit obligations at December 31, 2010 were 5.50% for the retirement plan and 5.25% for the restoration plan.

(2) The rate of compensation increase used to determine benefit obligations at December 31, 2011 ranged from 4% to 13%. The rate of compensation increase assumption was determined using a historical age based table grouped in five year age intervals.

(3) The discount rates used to determine net periodic benefit costs for the year ended December 31, 2011 were 5.50% for the retirement plan and 5.25% for the restoration plan. The discount rates used to determine net periodic benefit costs for the year ended December 31, 2009 were 6.00% for the retirement plan and 6.25% for the restoration plan.

Additional disclosures for the retirement and restoration plans are as follows:

	December 31, 2011	2010
(millions)		
Accumulated Benefit Obligation	$ 267	$ 230
Information for Pension Plans With Projected Benefit Obligations in Excess of Plan Assets		
Projected Benefit Obligation	293	262
Fair Value of Plan Assets	219	206
Information for Pension Plans With Accumulated Benefit Obligations in Excess of Plan Assets		
Accumulated Benefit Obligation	267	37
Fair Value of Plan Assets	219	-

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan’s asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. During 2011, we changed the plan’s target asset allocation from 70% equity and 30% fixed income to 60% equity and 40% fixed income. The change was made to more closely align the plan’s expected future payment streams with the expected duration of plan liabilities. The change was also made to reduce the plan’s market risk and the degree of volatility in the plan’s investments. Because a larger portion of the plans funds are now invested in fixed income, which are considered to be less risky investments, the plan’s returns will likely be reduced in times of market upswings, while losses will be reduced in times of market downswings. We assume the long-term asset mix will be consistent with the target asset allocation, with a range in the acceptable degree of variation in the plan’s asset allocation of plus or minus 10%. Based on these factors we assumed an average of 7.25% per annum over the life of the plan for the calculation of 2011 net periodic benefit cost. The assumption will be reduced to 6.50% for the calculation of 2012 net periodic benefit cost. No plan assets are expected to be returned to us in 2012.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

In order to determine an appropriate discount rate at December 31, 2011, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) and various AA corporate bond yields as of that date for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero-coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities. A 1% increase in the discount rate would have resulted in a decrease in net periodic benefit cost of approximately $3 million in 2011. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of approximately $2 million in 2011.

Assumed health care cost trend rates were as follows:

	December 31,			
	2011		2010	
Health Care Cost Trend Rate Assumed for Next Year	7.65	%	7.83	%
Ultimate Health Care Cost Trend Rate	4.50	%	4.50	%
Year Rate Reaches Ultimate Trend Rate	2030		2030	

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease	
(millions)			
Effect on Total Service and Interest Cost Components for 2011	$-	$-	
Effect on Year-End 2011 Postretirement Benefit Obligation	2	(1	)

Weighted-average asset allocations for the tax-qualified defined benefit pension plan are as follows:

	Target Allocation		Plan Assets			
	2012		2011		2010	
Asset Category						
Equity Securities	60	%	65	%	73	%
Fixed Income	40	%	35	%	27	%
Total	100	%	100	%	100	%

The investment policy for the tax-qualified defined benefit pension plan is determined by an employee benefits committee (the committee) with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. The fixed income allocation is expected to directionally track a portion of the plan's liabilities, thus reducing overall plan interest rate risk. A 1% increase (decrease) in the expected return on plan assets would have resulted in a (decrease) increase, respectively, in net periodic benefit cost of approximately $2 million in 2011.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2012, we had cumulative asset losses of approximately $10 million, which remain to be recognized in the calculation of the market-related value of assets.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Additional fair value disclosures about plan assets are as follows:

	Fair Value Measurements Using			
Asset Category (millions)	Quoted Prices in Active Markets for Identical Assets (Level 1) (1)	Significant Observable Inputs (Level 2) (1)	Significant Unobservable Inputs (Level 3) (1)	Total
December 31, 2011				
Federal Money Market Funds	$ 1	$ -	$ -	$ 1
Mutual Funds				
Large Cap Funds	66	-	-	66
Mid Cap Funds	10	-	-	10
Blended Funds	6	-	-	6
Emerging Markets Funds	6	-	-	6
Fixed Income Funds	77	-	-	77
Common Collective Trust Funds				
Large Cap Funds	-	17	-	17
Small Cap Funds	-	12	-	12
International Funds	-	24	-	24
Total	$ 166	$ 53	$ -	$ 219
December 31, 2010				
Federal Money Market Funds	$ 2	$ -	$ -	$ 2
Mutual Funds				
Large Cap Funds	69	-	-	69
Mid Cap Funds	10	-	-	10
Blended Funds	6	-	-	6
Emerging Markets Funds	7	-	-	7
Fixed Income Funds	55	-	-	55
Common Collective Trust Funds				
Large Cap Funds	-	16	-	16
Small Cap Funds	-	12	-	12
International Funds	-	29	-	29
Total	$ 149	$ 57	$ -	$ 206

(1) See Note 1. Summary of Significant Accounting Policies - Fair Value Measurements for a description of the fair value hierarchy.

Additional information about plan assets, including methods and assumptions used to estimate the fair values of plan assets, is as follows:

Federal Money Market Funds   Investments in federal money market funds consist of portfolios of high quality fixed income securities (such as US Treasury securities) which, generally, have maturities of less than one year. The fair value of these investments is based on quoted market prices for identical assets as of the measurement date.

Mutual Funds   Investments in mutual funds consist of diversified portfolios of common stocks and fixed income instruments. The common stock mutual funds are diversified by market capitalization and investment style as well as economic sector and industry. The fixed income mutual funds are diversified primarily in government bonds, mortgage backed securities, and corporate bonds, most of which are rated investment grade. The fair values of these investments are based on quoted market prices for identical assets as of the measurement date.

Common Collective Trust Funds   Investments in common collective trust funds consist of common stock investments in both US and non-US equity markets. Portfolios are diversified by market capitalization and investment style as well as economic sector and industry. The investments in the non-US equity markets are used to further enhance the plan’s overall equity diversification which is expected to moderate the plan’s overall risk volatility. In addition to the normal risk associated with stock market investing, investments in foreign equity markets may carry additional political, regulatory, and currency risk which is taken into account by the committee in its deliberations. The fair value of these investments is based on quoted prices for similar assets in active markets. All of the investments in common collective trust funds represent exchange-traded securities with readily observable prices.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Contributions   We expect to make cash contributions of approximately $13 million to the pension plan during 2012. We expect to make cash contributions of $3 million to the unfunded restoration plan and $1 million to the medical and life plans in 2012, which amounts equal expected benefit payments from those plans. (Unaudited).

Estimated Future Benefit Payments   As of December 31, 2011, the following future benefit payments are expected to be paid:

(millions)	Retirement and Restoration Plans	Medical and Life Plans
2012	$ 21	$ 1
2013	23	1
2014	25	1
2015	24	2
2016	26	2
Years 2017 to 2020	141	11

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2011 and includes estimated future employee service.

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 $14 million in 2011, $11 million in 2010, and $9 million in 2009.

Deferred Compensation Plans   We have a non-qualified deferred compensation plan for which participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants may elect to receive distributions in either cash or shares of our common stock. Components of the rabbi trust are as follows:

	December 31,	
(millions, except share amounts)	2011	2010
Rabbi Trust Assets		
Mutual Fund Investments	$82	$96
Noble Energy Common Stock (at Fair Value)	80	82
Total Rabbi Trust Assets	162	178
Liability Under Related Deferred Compensation Plan	$162	$178
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	848,940	949,040

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 16. 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. The amounts payable to the plan participants are included in other noncurrent liabilities in the consolidated balance sheets and include the market value of the shares of our common stock. Approximately 800,000 shares, or 94%, of our common stock held in the plan at December 31, 2011 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next eight years. Distributions of 100,000 shares were made in each of 2010 and 2011. In addition, plan participants sold 100 shares of our common stock in 2011, 100 shares in 2010, and 1,892 shares in 2009. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $17 million in 2011, $17 million in 2010 and were de minimis in 2009.

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 $8 million in 2011, $15 million in 2010 and $23 million in 2009.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. Deferred compensation liabilities of $60 million, $51 million and $45 million were outstanding at December 31, 2011, 2010 and 2009, respectively, under the unfunded plan.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 15. Stock-Based Compensation

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2011	2010	2009
(millions)			
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$42	$39	$36
Exploration Expense and Other	16	15	13
Total Stock-Based Compensation Expense	$58	$54	$49
Tax Benefit Recognized	$(20)	$(19)	$(17)

Stock Option and Restricted Stock Plans and Incentive Plan Our stock option and restricted stock plans and incentive plan 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, 2011, 16,216,198 shares of our common stock were reserved for issuance, including 9,143,929 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.

2004 Long-Term Incentive Plan Under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (the 2004 LTIP), the Committee may make incentive awards to our key employees and those of our subsidiaries. Incentive compensation is based upon the attainment of specific market and performance goals established by the Committee. Awards may be in the form of stock options or restricted stock or in the form of performance units or other incentive measurements providing for the payment of bonuses in cash, or in any combination thereof, as determined by the Committee in its discretion. Stock options granted and restricted stock awarded under the 2004 LTIP are granted and awarded pursuant to the terms of the 1992 Plan.

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, 2011, 705,778 shares of our common stock were reserved for issuance, including 504,841 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 their vesting date and their expiration date.
- Expected volatility The expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the expected term of the award. We use the historical volatility of our common stock for a period equal to the expected term of the option prior to the date of grant. We believe that historical volatility produces an estimate that is representative of our expectations about the future volatility of our common stock over the expected term.
- Risk-free rate The risk-free rate is the implied yield available on US Treasury securities with a remaining term equal to the expected term of the option. We base our risk-free rate on a weighting of five and seven year US Treasury securities as of the date of grant.
- Dividend yield The dividend yield represents the value of our stock's annualized dividend as compared to our stock's average price for the three-year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three-year period ended prior to the date of grant.

The assumptions used in valuing stock options granted were as follows:

	Year Ended December 31,		
	2011	2010	2009
(weighted averages)			
Expected Term (in Years)	5.7	5.6	5.5
Expected Volatility	36.2 %	35.4 %	43.0 %
Risk-Free Rate	2.2 %	2.6 %	2.0 %
Expected Dividend Yield	1.1 %	1.1 %	1.2 %
Weighted Average Grant-Date Fair Value	$30.17	$25.05	$19.14

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, 2010	6,266,960	$ 52.87		
Granted	992,488	90.34		
Exercised	(837,096)	45.59		
Forfeited	(56,536)	75.01		
Outstanding at December 31, 2011	6,365,816	$ 59.47	6.1	$ 223
Exercisable at December 31, 2011	4,315,415	$ 51.13	5.1	$ 187

The total intrinsic value of options exercised was $40 million in 2011, $68 million in 2010, and $19 million in 2009.

As of December 31, 2011, $30 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.3 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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, 2010	1,232,867	$66.11
Awarded	407,336	90.32
Vested	(633,312)	67.84
Forfeited	(27,634)	73.26
Outstanding at December 31, 2011	979,257	$74.87

The total fair value of restricted stock that vested was $57 million in 2011, $43 million in 2010, and $4 million in 2009.

The weighted average award-date fair value of restricted stock awarded was $90.32 per share in 2011, $75.07 per share in 2010, and $51.63 per share in 2009.

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, 2011, $37 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 1.3 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.

Note 16. 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 using a discounted cash flow method 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.

Interest Rate Derivative Instrument We estimate the fair values of forward starting swaps using a discounted cash flow method based on published interest rate yield curves as of the date of the estimate. The fair values of interest rate derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of interest rate derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. As of December 31, 2011 there were no outstanding interest rate derivative instruments. 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.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (1)	Significant Unobservable Inputs (Level 3) (1)	Adjustment (2)	Fair Value Measurement
December 31, 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)
December 31, 2010					
Financial Assets					
Mutual Fund Investments	$ 112	$ -	$ -	$ -	$ 112
Commodity Derivative Instruments	-	106	-	(44)	62
Financial Liabilities					
Commodity Derivative Instruments	-	(119)	-	44	(75)
Interest Rate Derivative Instrument	-	(63)	-	-	(63)
Portion of Deferred Compensation					
Liability Measured at Fair Value	(178)	-	-	-	(178)

(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 master netting agreements that allow us to 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.

See Note 3. Acquisitions and Divestitures for a discussion of the methods and assumptions used to estimate the fair values of the acquired assets.

Asset Impairments   Information about impaired assets as of the date of the assessment is as follows:

Description (millions)	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (1)	Significant Unobservable Inputs (Level 3) (1)	Net Book Value (2)	Total Pre-tax (Non-cash) Impairment Loss
Year Ended December 31, 2011					
Impaired Oil and Gas Properties	$-	$-	$ 213	$972	$759
Year Ended December 31, 2010					
Impaired US Oil and Gas Properties	-	-	30	174	144
Year Ended December 31, 2009					
Impaired US Oil and Gas Properties	-	-	363	867	504
Impaired Investment in Ecuador	-	-	72	172	100

(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 date of assessment.

See Note 4. Asset Impairments for a discussion of the methods and assumptions used to estimate the fair values of the impaired assets.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Additional Fair Value Disclosures

Debt The fair value of fixed-rate debt is estimated based on the published market prices for the same or similar issues. The carrying amount of floating-rate debt approximates fair value because the interest rates paid on such debt are set for periods of three months or less. The carrying amounts of the CONSOL installment payments approximate fair value because they have been discounted at the prevailing market rates for similar instruments. See Note 12. Long-Term Debt.

Fair value information regarding our debt is as follows:

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Debt, Net of Unamortized Discount (1)	$4,114	$4,733	$1,977	$2,302

(1) Excludes Aseng FPSO lease obligation.

Note 17. Earnings Per Share

The following table summarizes the calculation of basic and diluted earnings per share:

	Year Ended December 31,		
	2011	2010	2009
(millions, except per share amounts)			
Net Income (Loss)	453	725	(131)
Weighted Average Number of Shares Outstanding, Basic	176	175	173
Incremental Shares from Assumed Conversion of			
Dilutive Options and Restricted Stock	3	2	-
Weighted Average Number of Shares Outstanding, Diluted	179	177	173
Earnings (Loss) Per Share, Basic	$2.57	$4.15	$(0.75)
Earnings (Loss) Per Share, Diluted	2.54	4.10	(0.75)
Additional Information			
Antidilutive stock options and shares of restricted stock	2	2	4
Weighted average option exercise price per share	$85.40	$74.01	$60.40
Incremental stock options and shares of restricted stock excluded from calculation of diluted earnings in loss period	-	-	2

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 18. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five 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 and Senegal/Guinea-Bissau); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. Other International includes China, Ecuador (through May 2011), and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	North Sea	Other Int'l, Corporate
Year Ended December 31, 2011						
Revenues from Third Parties	$ 3,568	$2,125	$592	$ 307	$357	$187
Income from Equity Method Investees	195	2	193	-	-	-
Total Revenues (1)	3,763	2,127	785	307	357	187
DD&A	965	758	69	25	87	26
Gain on Divestiture	(25)	-	-	-	-	(25)
Asset Impairments	759	757	-	-	2	-
(Gain) Loss on Commodity Derivative Instruments	(42)	(74)	32	-	-	-
Income (Loss) Before Income Taxes	715	96	561	228	213	(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)	16,444	11,201	2,728	1,751	544	220
Year Ended December 31, 2010						
Revenues from Third Parties	$ 2,924	$1,893	$349	$ 191	$309	$182
Reclassification from AOCL (3)	(20)	(20)	-	-	-	-
Income from Equity Method Investees	118	-	118	-	-	-
Total Revenues (1)	3,022	1,873	467	191	309	182
DD&A	883	719	39	22	64	39
Net Gain on Asset Sales	(113)	(113)	-	-	-	-
Asset Impairments	144	119	-	25	-	-
(Gain) Loss on Commodity Derivative Instruments	(157)	(168)	11	-	-	-
Income (Loss) Before Income Taxes	1,031	713	355	119	183	(339)
Equity Method Investments	285	-	285	-	-	-

Additions to Long-Lived Assets	2,789	1,796	612	270	64	47
Goodwill at End of Year	696	696	-	-	-	-
Total Assets at End of Year (2)	13,282	9,091	2,270	919	770	232
Year Ended December 31, 2009						
Revenues from Third Parties	$ 2,287	$ 1,484	$ 340	$ 144	$ 153	$ 166
Reclassification from AOCL (3)	(58)	(29)	(29)	-	-	-
Income from Equity Method Investees	84	-	84	-	-	-
Total Revenues (1)	2,313	1,455	395	144	153	166
DD&A	816	689	38	20	34	35
Asset Impairments	604	504	-	-	-	100
Gain on Commodity Derivative Instruments	110	73	37	-	-	-
Income (Loss) Before Income Taxes	(264)	(287)	257	98	62	(394)
Equity Method Investments	303	-	303	-	-	-
Additions to Long-Lived Assets	1,282	911	124	103	103	41
Goodwill at End of Year	758	758	-	-	-	-
Total Assets at End of Year (2)	11,807	8,669	1,731	486	635	286

(1) Revenues from third parties for all foreign countries, in total, were $1.6 billion in 2011, $1.0 billion in 2010, and $791 million in 2009.

(2) Long-lived assets located in all foreign countries, in total, were $3.5 billion, $2.4 billion, and $1.6 billion at December 31, 2011, 2010, and 2009, respectively.

(3) Revenues through 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 19. 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, 2011				
Glencore Energy UK Ltd	24	%	16	%
Shell Trading (US) Company	17	%	12	%
Year Ended December 31, 2010				
Glencore Energy UK Ltd	17	%	11	%
Year Ended December 31, 2009				
Suncor Energy Marketing	25	%	16	%

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, 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 20. Additional Shareholders' Equity Information

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

	Year Ended December 31,	
	2011	2010

Common Stock Shares Issued		
Shares, Beginning of Period	195,440,048	193,550,391
Exercise of Common Stock Options	837,096	1,502,454
Restricted Stock Awards, Net of Forfeitures	379,702	387,203
Shares, End of Period	196,656,846	195,440,048
Treasury Stock		
Shares, Beginning of Period	18,650,064	18,582,301
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	186,556	167,863
Rabbi Trust Shares Distributed and/or Sold	(100,100)	(100,100)
Shares, End of Period	18,736,520	18,650,064

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Accumulated Other Comprehensive Loss			
(millions)	Oil and Gas Cash Flow Hedges	Interest Rate Cash Flow Hedges	Pension-Related and Other	Total
December 31, 2008	$(48)	$(3)	$(59)	$(110)
Realized Amounts Reclassified Into Earnings	36	1	2	39
Net Change in Other	-	-	(4)	(4)
December 31, 2009	(12)	(2)	(61)	(75)
Realized Amounts Reclassified Into Earnings	12	1	3	16
Unrealized Change in Fair Value	-	(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)

All amounts in the table above are reported net of tax. The effective income tax rate applied to AOCL was 37.6% at December 31, 2008 and 35.0% at December 31, 2009, 2010 and 2011.

Note 21. 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.

During 2011, we received two Notices of Alleged Violation (NOAV) from the COGCC regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. At this time, the COGCC has not established a proposed penalty for either NOAV. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

CONSOL Carried Cost Obligation Based on the December 31, 2011 Henry Hub natural gas price strip, we forecast our CONSOL Carried Cost Obligation will be suspended throughout the 2012 fiscal year and resume during first quarter of 2013. 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.

CONE MARC The CONE MARC, which we expect to total approximately $23 million in 2012, is included in transportation and gathering below. Amounts to be paid in years beyond 2012 have not yet been determined by the partners.

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 $31 million in 2011, $27 million in 2010, and $22 million in 2009.

Minimum commitments as of December 31, 2011 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering	Operating Lease Obligations	FPSO Lease Payments(1)	Total
2012	$ 980	$ 55	$ 45	$ 72	$ 1,152
2013	93	49	27	72	241
2014	21	37	28	72	158
2015	13	29	27	70	139
2016	-	29	26	45	100
2017 and Thereafter	-	267	32	155	454
Total	$ 1,107	$ 466	$ 185	$ 486	$ 2,244

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs, and began during fourth quarter of 2011 once the Aseng FPSO initiated producing operations. See Note 12. Long-Term Debt.

Table of Contents

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

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, 2011, 2010, and 2009 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. Thus far in 2012, there have been significant declines in natural gas prices. Further significant declines in natural gas prices or significant declines in crude oil prices, could result in negative reserves revisions.

SEC and FASB Rule-Making Activity Effective December 31, 2009, we implemented the SEC's final rules on the Modernization of Oil and Gas Reporting. The new rules included revisions designed to modernize the oil and gas company reserves reporting requirements.

The rule changes, including those related to pricing and technology, are included in our reserves estimates as of December 31, 2009, 2010 and 2011.

In addition, in 2010, the FASB issued ASU 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. ASU 2010-03 amended existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. We adopted the new standards effective December 31, 2009. The new standards were applied prospectively as a change in estimate.

Impact of Implementation Implementation of the SEC's updated rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of 12-month average pricing at December 31, 2009 as required by the updated rules resulted in a decrease in proved reserves of approximately 27 MMBoe. Use of year-end prices as required by the previous rules would have resulted in an increase in proved reserves of approximately 34 MMBoe at December 31, 2009. Therefore, the total impact of the new price methodology was negative reserves revisions of 61 MMBoe. In addition, the new proved undeveloped reserves rules resulted in a reduction of proved reserves of approximately 18 MMBoe due to limiting proved undeveloped reserves locations to those scheduled to be drilled within the next five years. The majority of the reserves reclassified out of proved reserves were associated with the DJ Basin, where we maintain an extensive multi-year development program.

Because we use quarter-end reserves and add back current period production to calculate quarterly DD&A, adoption of the updated FASB standards had an impact on fourth quarter 2009 DD&A expense. We estimated the impact of using 12-month average commodity prices, as required by the updated standards, instead of year-end commodity prices, to be an increase in fourth quarter 2009 DD&A expense of approximately $16 million (or $0.06 per share).

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, 2011. See Items 1. and 2. Business and Properties – Proved Reserves Disclosures.

Geographic Areas   Our supplemental disclosures are grouped by geographic area and include the United States, Equatorial Guinea, Israel and Other International. Other International includes Ecuador (through November 24, 2010), North Sea, China, Senegal/Guinea-Bissau, Cameroon, Cyprus, Nicaragua, France and other new ventures, where applicable. Operations in Equatorial Guinea, China, Cyprus, and Senegal/Guinea-Bissau are conducted in accordance with the terms of PSCs. Operations in Cameroon are conducted in accordance with the terms of a PSC and a mining concession. Operations in other foreign locations are conducted in accordance with concession agreements, permits or licenses.

Table of Contents

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

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.

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).

Table of Contents

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

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

	Crude Oil, Condensate and NGLs (MMBbls)			
	United States	Equatorial Guinea	Other Int'l (1)	Total
Proved Reserves as of:				
December 31, 2008	198	75	38	311
Revisions of Previous Estimates (2)	(5)	(1)	-	(6)
Extensions, Discoveries and Other Additions (3)	32	26	1	59
Purchase of Minerals in Place (4)	1	-	-	1
Sale of Minerals in Place (5)	-	-	-	-
Production (6)	(17)	(8)	(4)	(29)
December 31, 2009	209	92	35	336
Revisions of Previous Estimates (2)	15	1	(5)	11
Extensions, Discoveries and Other Additions (3)	25	26	3	54
Purchase of Minerals in Place (4)	23	-	-	23
Sale of Minerals in Place (5)	(28)	-	-	(28)
Production (6)	(19)	(7)	(5)	(31)
December 31, 2010	225	112	28	365
Revisions of Previous Estimates (2)	(5)	2	(6)	(9)
Extensions, Discoveries and Other Additions (3)	43	-	2	45
Purchase of Minerals in Place (4)	-	-	-	-
Sale of Minerals in Place (5)	-	-	-	-
Production (6)	(19)	(8)	(5)	(32)
December 31, 2011	244	106	19	369
Proved Developed Reserves as of:				
December 31, 2008	121	57	21	199
December 31, 2009	122	49	23	194
December 31, 2010	119	43	21	183
December 31, 2011	134	60	13	207
Proved Undeveloped Reserves as of:				
December 31, 2008	77	18	17	112
December 31, 2009	87	43	12	142
December 31, 2010	106	69	7	182
December 31, 2011	110	46	6	162

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

(2) The 2009 negative revisions within the US are primarily due to performance revisions, the majority of which related to Main Pass (10 MMBbl) and reclassifications of PUDs to probable reserves as a result of the SEC's new five year development rule (5 MMBbl), partially offset by higher year-end prices (10 MMBbl). 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 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.

(3) The 2009 increase in proved reserves includes 20 MMBbl related to the ongoing development of Wattenberg, 11 MMBbl in the deepwater Gulf of Mexico for the Santa Cruz, Isabela and Swordfish fields, and 26 MMBbl in Equatorial Guinea for the Aseng field. 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.

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

(5) We sold non-core, onshore US assets in the Mid-Continent and Illinois Basin in 2010. See Note 3. Acquisitions and Divestitures.

(6) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in each of 2011, 2010, and 2009.

Table of Contents

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, 2008	1,859	978	273	205	3,315
Revisions of Previous Estimates (2)	(397)	49	(2)	-	(350)
Extensions, Discoveries and Other Additions (3)	211	-	5	2	218
Purchase of Minerals in Place (4)	6	-	-	-	6
Sale of Minerals in Place (5)	-	-	-	-	-
Production	(145)	(87)	(42)	(11)	(285)
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
Proved Developed Reserves as of:					
December 31, 2008	1,268	700	216	201	2,385
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
Proved Undeveloped Reserves as of:					
December 31, 2008	591	278	57	4	930
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

(1) Other International includes the North Sea, Ecuador (at December 31, 2009 and 2008), and China. See Note 3. Acquisitions and Divestitures and Note 4. Asset Impairments.

(2) The 2009 negative revisions in the US are primarily due to lower year-end prices (224 Bcf), reclassifications of PUDs to probable reserves as a result of the SEC's new five year development rule (75 Bcf), and increased lease operating expense and various well performance issues (98 Bcf). 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 revisions in 2009 and 2010 are primarily due to additional production allowances related to LNG sales. Israel's revisions in 2010 reflect a change in the likelihood that the Noa field will 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.

(3) The 2009 increase in US proved reserves is primarily due to ongoing low-risk development programs onshore in Wattenberg, the Rocky Mountain area, and East Texas. 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 have decided to develop.

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

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

Table of Contents

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:

(millions)	United States	Equatorial Guinea	Israel	Other Int'l (1)	Total
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 (3)	$42	$288	$ 178	$111	$619
Year Ended December 31, 2010					
Revenues					
Sales (4)	$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 (3)	$297	$190	$ 97	$167	$751
Year Ended December 31, 2009					
Revenues					
Sales (4)	$1,341	$340	$ 144	$235	$2,060
Sales to Affiliated Power Plant	-	-	-	35	35
Total Revenues	1,341	340	144	270	2,095
Production Costs (2)	417	50	13	79	559
Exploration Expense	75	1	10	24	110
DD&A	689	38	21	50	798
Asset Impairments	504	-	-	100	604
Income before Income Taxes	(344)	251	100	17	24
Income Tax Expense	(108)	59	20	6	(23)
Results of Operations (3)	$ (236)	$ 192	$ 80	$ 11	$ 47

(1) Other International includes the North Sea, Ecuador (through November 24, 2010), China, Cameroon, Cyprus, Senegal/Guinea-Bissau, Nicaragua, France 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) 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.

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

Table of Contents

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, 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
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
Year Ended December 31, 2009					
Property Acquisition Costs					
Proved (3)	$(5)	$-	$-	$-	$(5)
Unproved (4)	89	1	-	2	92
Total Acquisition Costs	84	1	-	2	87
Exploration Costs (5)	189	30	81	13	313
Development Costs (6)	711	100	33	129	973
Total Consolidated Operations	$984	$131	$114	$144	$1,373

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes the North Sea, Ecuador (through November 24, 2010), China, Cameroon, Cyprus, Senegal/Guinea-Bissau, Nicaragua, France 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, $352 million related to the DJ Basin asset acquisition in 2010 and a $6 million downward purchase price adjustment related to the Mid-Continent acquisition in 2009.

(4) 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 Profound block), $31 million related to additional acreage in the DJ Basin and $58 million related to other onshore US in 2011; $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 in 2010; $56 million for deepwater Gulf of Mexico lease

blocks and the remainder primarily for other onshore US lease acquisitions in 2009.

(5) 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. 2009 exploration costs include drilling and completion costs of $57 million in deepwater Gulf of Mexico, $19 million in Equatorial Guinea and $71 million in Israel.

(6) Worldwide development costs include amounts spent to develop PUDs of approximately $1.4 billion in 2011, $1.1 billion in 2010 and $440 million in 2009. Equatorial Guinea development costs include non-cash accruals related to estimated construction progress to date on an FSPO to be used in the development of the Aseng field of $66 million in 2011, $266 million in 2010 and $29 million in 2009. These capitalized costs are included in development costs as the Aseng FPSO is constructed. US development costs include increases in asset retirement obligations of $115 million in 2011, $15 million in 2010, and $11 million in 2009. Other international development costs include increases in asset retirement obligations of $13 million in 2011, $2 million in 2010, and $5 million in 2009.

Table of Contents

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

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, 2011	December 31, 2010
(millions)		
Unproved Oil and Gas Properties (1)	$1,519	$1,081
Proved Oil and Gas Properties (2)	16,184	13,312
Total Oil and Gas Properties	17,703	14,393
Accumulated DD&A	(5,063)	(4,270)
Net Capitalized Costs	$12,640	$10,123

(1) Unproved oil and gas properties includes $874 million, including $792 million for Marcellus Shale at December 31, 2011, and $304 million at December 31, 2010, remaining from the allocation of costs to unproved properties acquired in previous acquisitions.

(2) Proved oil and gas properties include asset retirement costs of $310 million and $208 million at December 31, 2011 and 2010, respectively.

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, 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
	3,941	1,589	3,530	127	9,187

10% Annual Discount for Estimated Timing of Cash Flows					
Standardized Measure of Discounted Future Net Cash Flows	$4,035	$2,733	$1,703	$535	$9,006
December 31, 2009					
Future Cash Inflows (2)	$16,196	$5,151	$769	$2,832	$24,948
Future Production Costs (3)	5,390	1,185	96	983	7,654
Future Development Costs	3,056	1,059	126	315	4,556
Future Income Tax Expense	2,227	956	135	630	3,948
Future Net Cash Flows	5,523	1,951	412	904	8,790
10% Annual Discount for Estimated Timing of Cash Flows	2,672	814	93	279	3,858
Standardized Measure of Discounted Future Net Cash Flows	$2,851	$1,137	$319	$625	$4,932

(1) Other International includes the North Sea, Ecuador (at December 31, 2009), and China. 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.

Table of Contents

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

Prices and Other Assumptions in Discounted Future Net Cash Flows (Unaudited) Future cash inflows are computed by applying a 12-month average commodity price, adjusted for location and quality differentials on a field-by-field basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l (1)	Total
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
December 31, 2009					
Average Crude Oil, Condensate and NGL Price per Bbl	$50.80	$53.46	$-	$59.55	$52.45
Average Natural Gas Price per Mcf	3.64	0.25	3.28	3.69	2.52

(1) Other International includes the North Sea, Ecuador (at December 31, 2009), and China. 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 2011 would change the discounted future net cash flows before income taxes by approximately $214 million. We estimate that a $0.10 per Mcf change in the average price of natural gas from the 12-month average price for 2011 would change the discounted future net cash flows before income taxes by approximately $221 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 $2.4 billion in 2012, $1.3 billion in 2013 and $1.0 billion in 2014.

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,		
	2011	2010	2009

(millions)			
Imbalance Receivables	$28	$25	$21
Imbalance Liabilities	22	18	12

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,		
	2011	2010	2009
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$9,006	$4,932	$4,864
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(2,864)	(2,251)	(1,528)
Net Changes in Prices and Production Costs	4,926	3,115	(878)
Extensions, Discoveries and Improved Recovery, Less Related Costs	2,039	2,820	815
Changes in Estimated Future Development Costs	(710)	(915)	(132)
Development Costs Incurred During the Period	2,529	1,869	971
Revisions of Previous Quantity Estimates	(1,320)	33	436
Purchases of Minerals in Place	115	646	5
Sales of Minerals in Place	(6)	(652)	-
Accretion of Discount	1,278	722	707
Net Change in Income Taxes	(1,540)	(1,487)	(75)
Change in Timing of Estimated Future Production and Other	(164)	174	(253)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	4,283	4,074	68
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$13,289	$9,006	$4,932

Table of Contents

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)					
2011 (1)					
Revenues	$899	$954	$924	$985	$3,763
Income (Loss) Before Income Taxes	37	425	722	(470)	715
Net Income (Loss)	14	294	441	(296)	453
Earnings (Loss) Per Share					
Basic (3)	$0.08	$1.66	$2.50	$(1.67)	$2.57
Diluted (3) (4)	0.08	1.61	2.39	(1.67)	2.54
2010 (2)					
Revenues	$733	$751	$755	$783	$3,022
Income (Loss) Before Income Taxes	343	320	298	69	1,031
Net Income (Loss)	237	204	232	52	725
Earnings (Loss) Per Share					
Basic (3)	$1.36	$1.17	$1.33	$0.29	$4.15
Diluted (3) (4)	1.34	1.10	1.31	0.29	4.10

(1) First quarter 2011 included the following:

- $8 million asset 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:

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

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 loss of $162 million (See Note 10. Derivative Instruments and Hedging Activities).

(2) First quarter 2010 included the following:

- $145 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $147 million (See Note 10. Derivative Instruments and Hedging Activities).

Second quarter 2010 included the following:

-

$96 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $63 million (See Note 10. Derivative Instruments and Hedging Activities); and

- $26 million rig contract termination expense due to the Deepwater Moratorium.

Third quarter 2010 included the following:

- $38 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $5 million (See Note 10. Derivative Instruments and Hedging Activities);
- $114 million gain on sale of non-core onshore US assets (See Note 3. Acquisitions and Divestitures); and
- $100 million asset impairment charges (See Note 4. Asset Impairments).

Fourth quarter 2010 included the following:

- $122 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $145 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $44 million asset impairment charges (See Note 4. Asset Impairments).

(3) The sum of the individual quarterly earnings (loss) per share amounts may not agree with year-to-date earnings per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of shares outstanding during that quarter.

(4) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while the Noble Energy shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculations 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, and for the three months ended June 30, 2010 excludes a deferred compensation gain of $9 million, net of tax.

Table of Contents

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, 2011. 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.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

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 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

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

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

PART IV

Item 15. Exhibits, Financial Statements 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.

Table of Contents

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 9, 2012	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, Chief Executive Officer and Director
Date: February 9, 2012	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Senior Vice President, Chief Financial Officer
Date: February 9, 2012	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 9, 2012
/s/ Kenneth M. Fisher Kenneth M. Fisher	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 9, 2012
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 9, 2012
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 9, 2012
/s/ Michael A. Cawley Michael A. Cawley	Director	February 9, 2012
/s/ Edward F. Cox Edward F. Cox	Director	February 9, 2012
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 9, 2012

/s/ Eric P. Grubman Eric P. Grubman	Director	February 9, 2012
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 9, 2012
/s/ Scott D. Urban Scott D. Urban	Director	February 9, 2012
/s/ William T. Van Kleef William T. Van Kleef	Director	February 9, 2012

Table of Contents

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 16, 2005, of the Registrant (filed as Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008, 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).

Table of Contents

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).

Table of Contents

Exhibit Number		Exhibit **
10.19*	—	Noble Energy, Inc. 2004 Long-Term Incentive Plan (as amended effective January 1, 2008), (filed as Exhibit 10.42 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.20*	—	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).
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
14.1	—	Noble Energy, Inc. Code of Business Conduct and Ethics, filed herewith.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Registered Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
23.3	—	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.
99.2	—	Report of Independent Public Accounting Firm — PricewaterhouseCoopers LLP, 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.