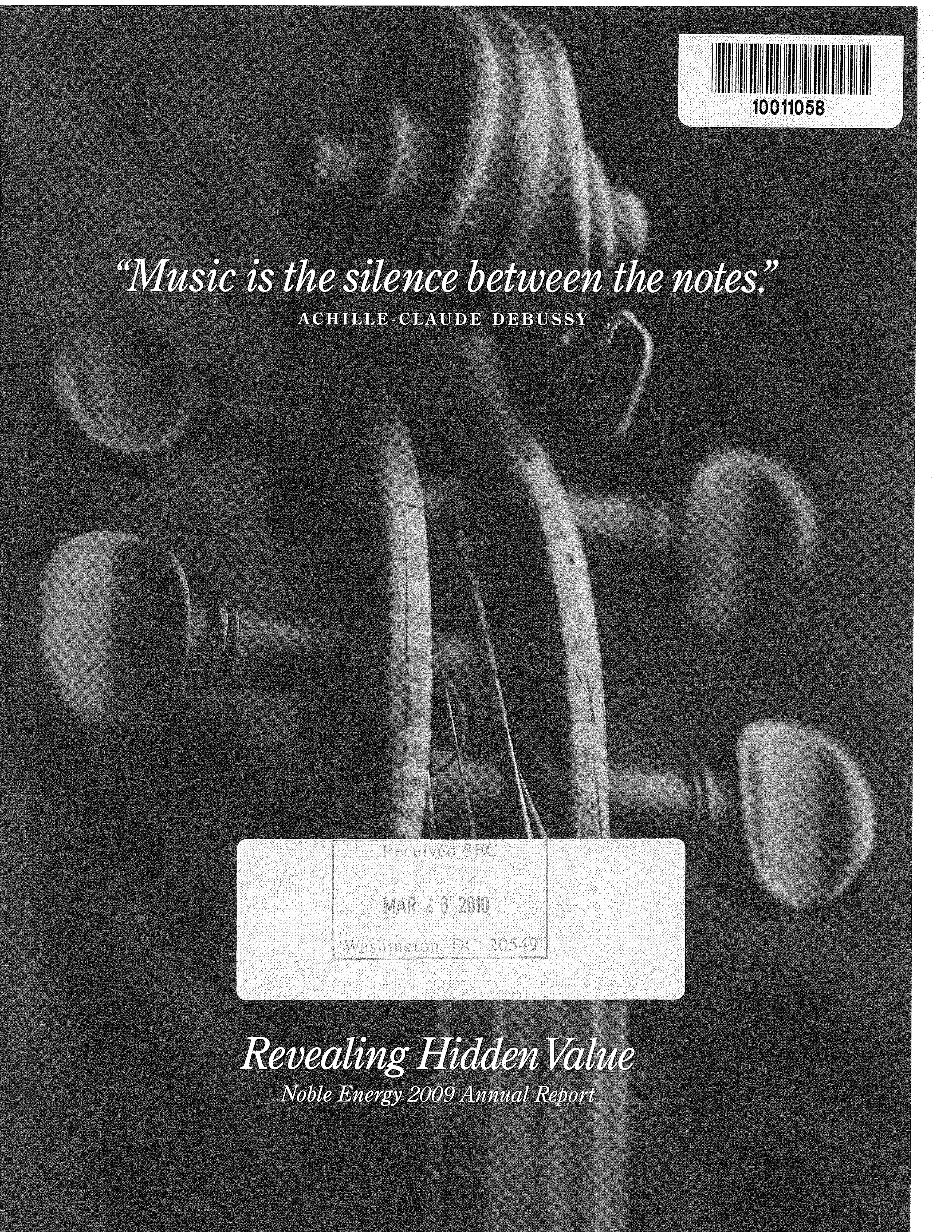


"Music is the silence between the notes."

ACHILLE-CLAUDE DEBUSSY

Revealing Hidden Value

Noble Energy 2009 Annual Report

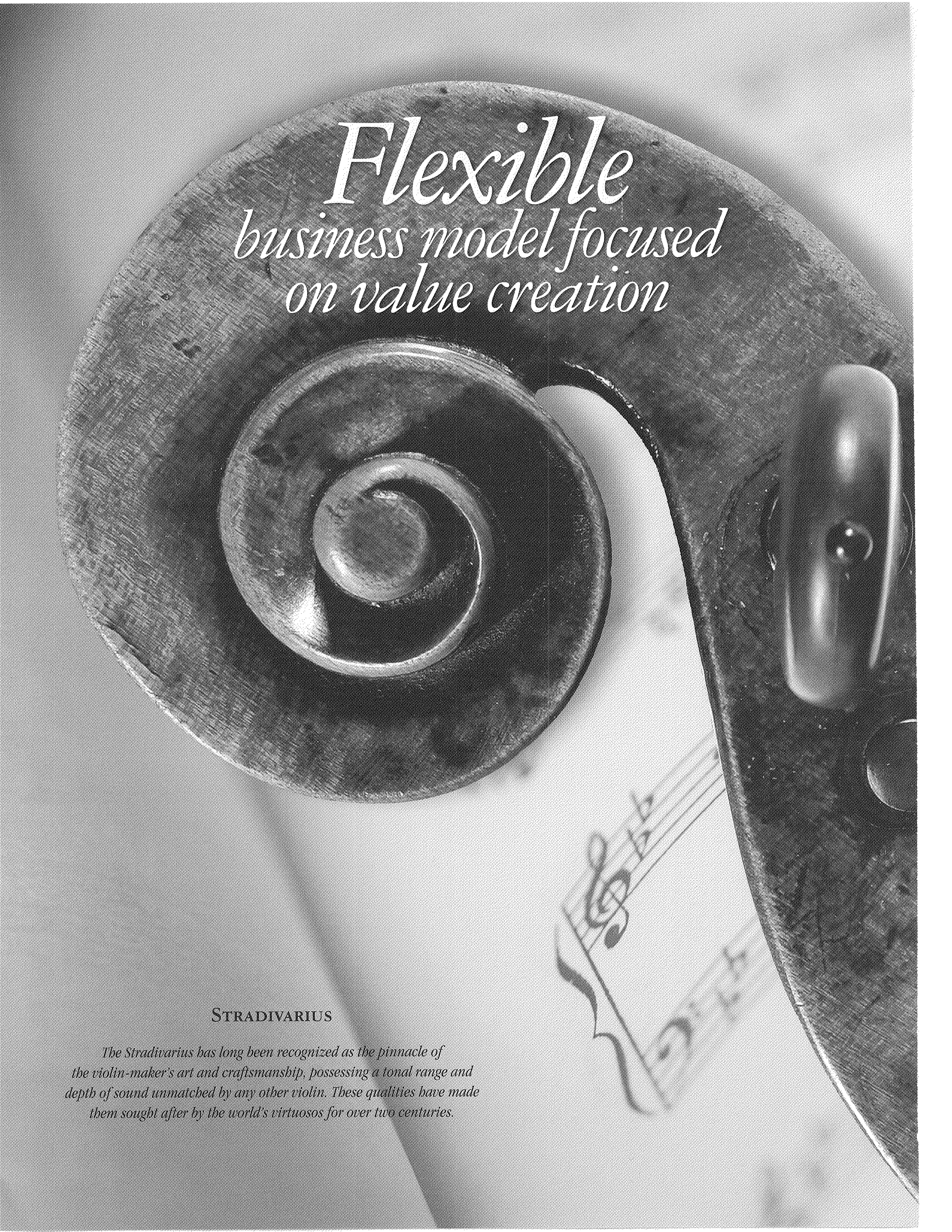
Noble Energy adheres to the highest standards of business, including honesty, integrity, transparency and fairness in interactions with all stakeholders. We are committed to helping meet global energy demand in a manner that protects the environment, as well as the health and safety of our employees and the public.

Composed

When you look at Noble Energy, you see a leading independent energy company with a finely tuned portfolio of assets, a track record of success and a sound strategy for the future.

But it's what you don't see that makes it that way.

Flexible business model focused on value creation

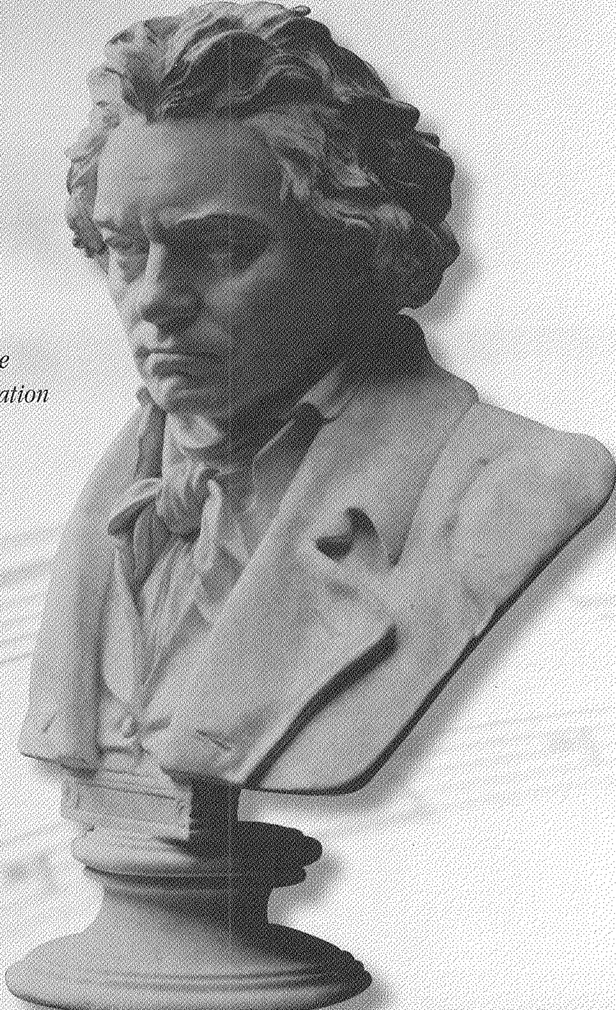


STRADIVARIUS

The Stradivarius has long been recognized as the pinnacle of the violin-maker's art and craftsmanship, possessing a tonal range and depth of sound unmatched by any other violin. These qualities have made them sought after by the world's virtuosos for over two centuries.

Beethoven

Composer and pianist Ludwig van Beethoven's contributions to classical music are profound. His influence on the development of the art form and its current interpretation is timeless, bridging generations and cultures to speak a universal language.



Best-in-class

exploration process delivering high-impact results

A culture dedicated to success and strong business principles

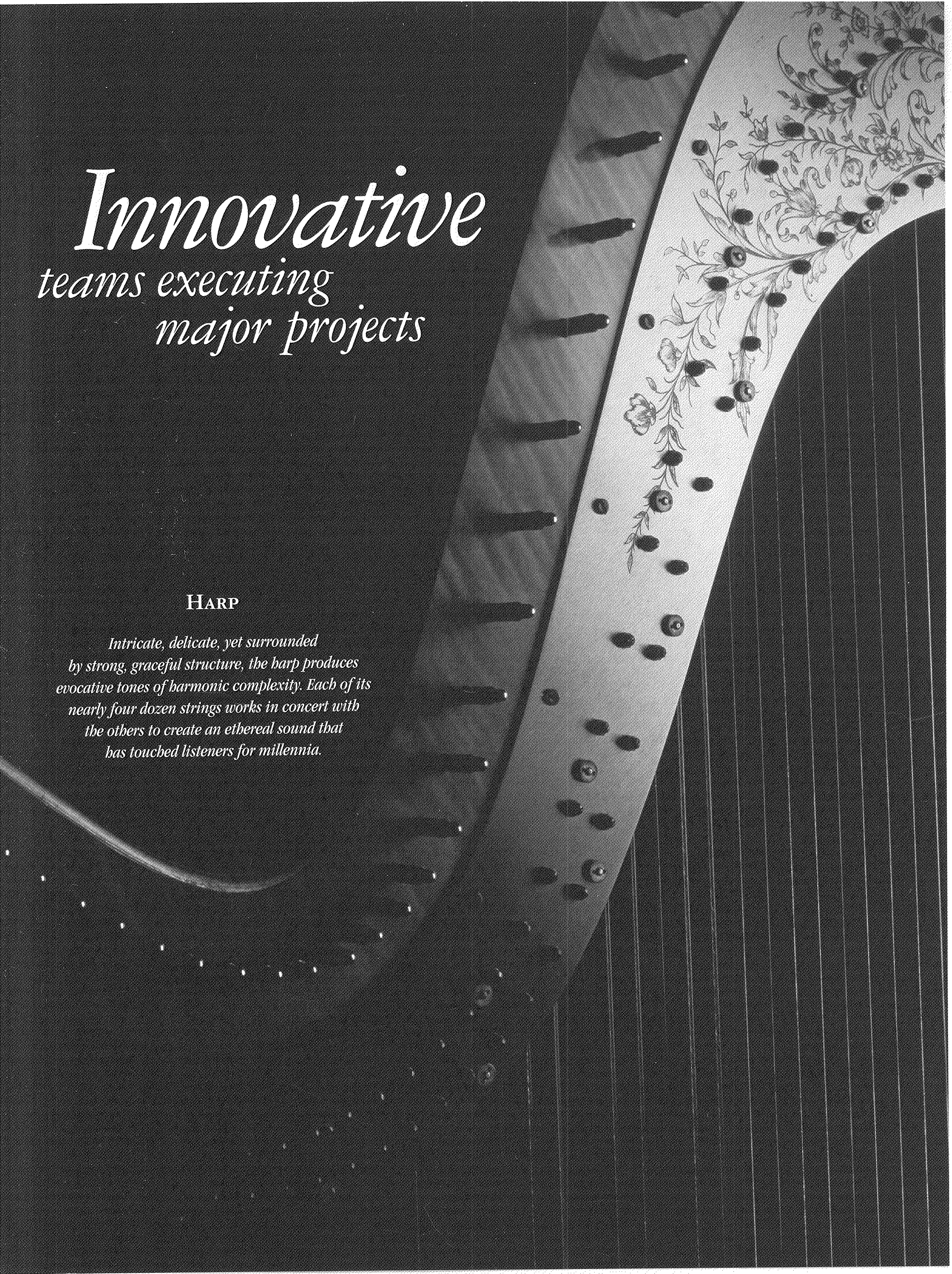
Carnegie Hall

To perform onstage at Carnegie Hall is to have developed one's abilities to their highest possible level, and it is there that each incandescent note lights the imagination of the audience.

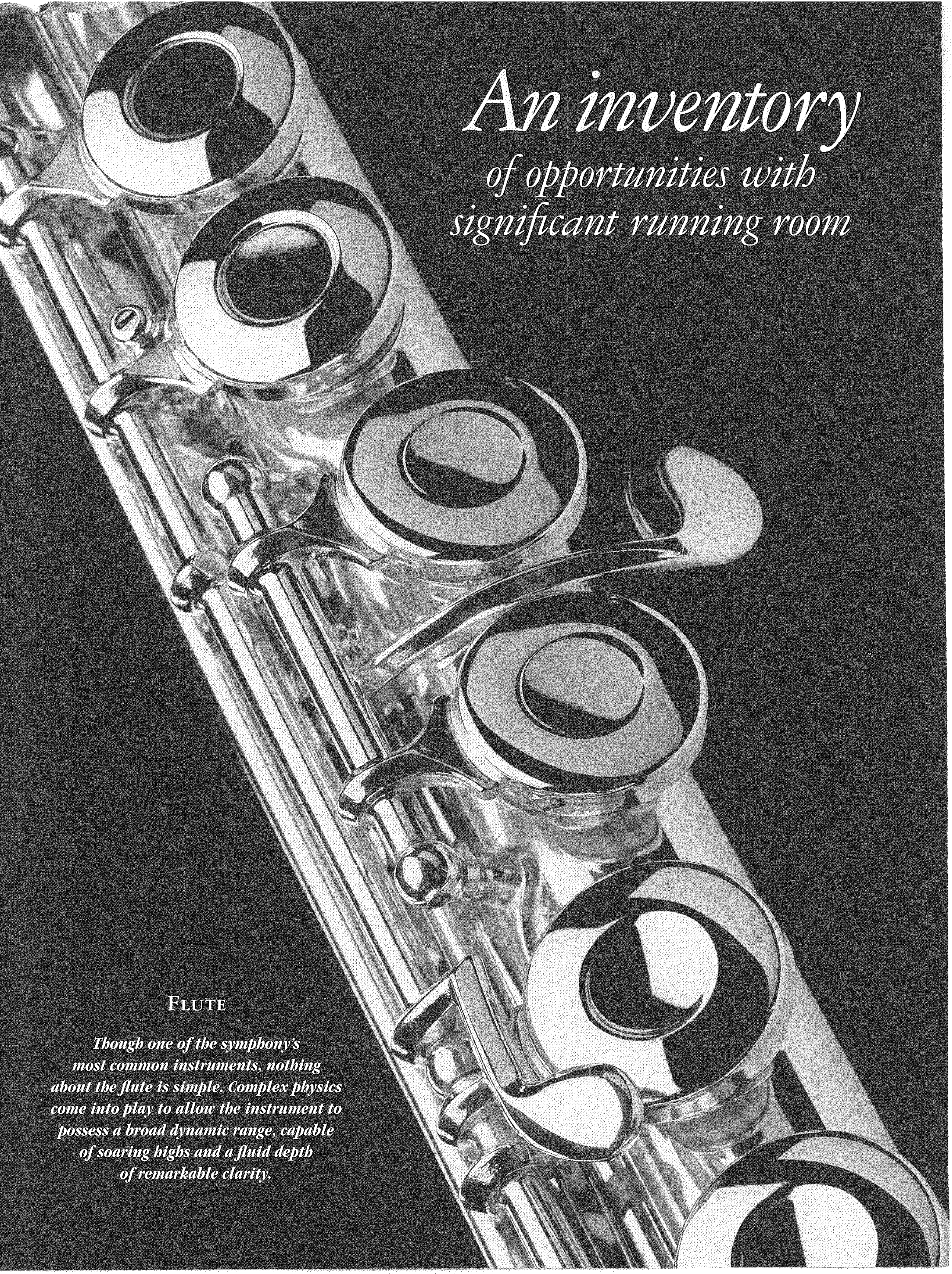
Innovative teams executing major projects

HARP

Intricate, delicate, yet surrounded by strong, graceful structure, the harp produces evocative tones of harmonic complexity. Each of its nearly four dozen strings works in concert with the others to create an ethereal sound that has touched listeners for millennia.

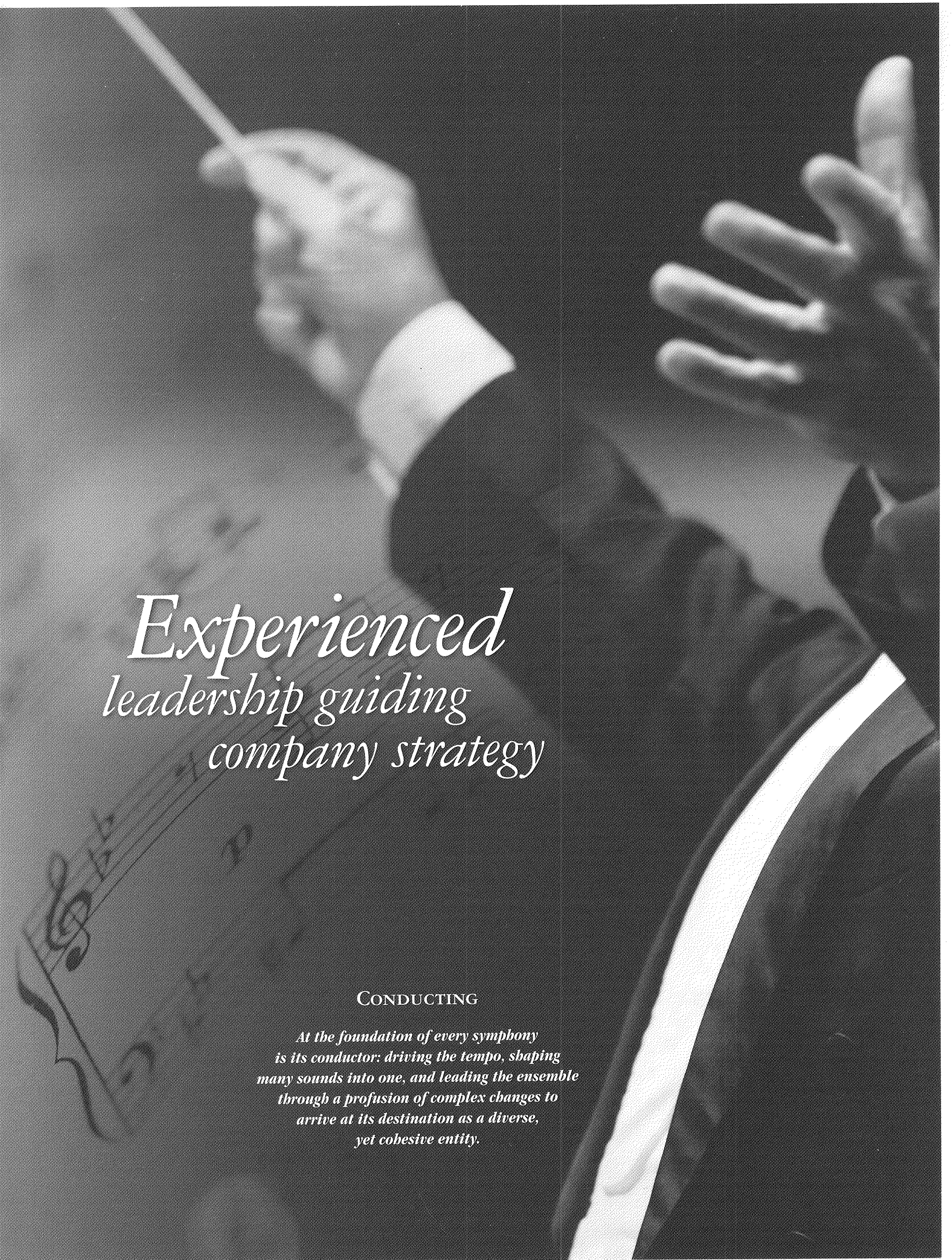


An inventory
of opportunities with significant running room



FLUTE

Though one of the symphony's most common instruments, nothing about the flute is simple. Complex physics come into play to allow the instrument to possess a broad dynamic range, capable of soaring highs and a fluid depth of remarkable clarity.



Experienced leadership guiding company strategy

Conducting

At the foundation of every symphony is its conductor: driving the tempo, shaping many sounds into one, and leading the ensemble through a profusion of complex changes to arrive at its destination as a diverse, yet cohesive entity.

Letter to Shareholders

2009 was a year of many challenges – for the global economies, our nation and our industry. Our country began the year in the middle of an economic crisis with no certainty as to when we would see improvement. With the recession, we experienced falling demand for energy, and by mid-January 2009 natural gas and oil prices had fallen dramatically from July 1 of the prior year. Natural gas prices continued to fall during the year reaching a low in early September that was 80 percent below what they were on July 1, 2008. Declining prices meant significantly reduced cash flows. Capital investment in drilling programs was forced lower, leading to the U.S. rig count falling over 50 percent over the same period.

Noble Energy entered 2009 well-prepared for this uncertain environment. Our balance sheet at the beginning of the year was strong, containing approximately $1 billion in cash. Our debt-to-book-capital ratio, net of cash, was a low 15 percent. However, even with this financial strength, we took early actions to better prepare Noble Energy. We initially reduced our 2009 capital program to approximately $1.6 billion from $2.3 billion in 2008 and later reduced it further to $1.4 billion. In addition, we successfully issued $1 billion in 10-year notes. These actions increased liquidity and gave us greater flexibility. As the year progressed, the environment continued to improve. Crude oil prices rallied from the lows experienced earlier in the year and helped to increase revenue and cash flow. Unfortunately, natural gas prices remained weak for most of the year. However, with approximately 50 percent of our U.S. gas production hedged, we significantly mitigated the effect of low gas prices.

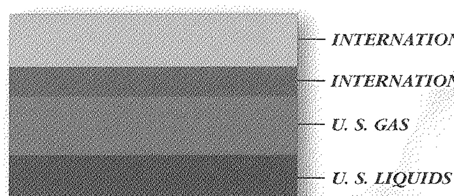
The lower commodity prices significantly impacted financial results. We ended the year with a net loss of $131 million, although this loss included approximately $600 million of before tax unrealized losses on commodity derivative instruments. In addition, there was another $600 million of before tax asset impairments primarily related to U.S. properties that were sensitive to low natural gas prices and to our investments in Ecuador. Capital expenditures for 2009 were carefully managed and ended the year at $1.3 billion. As a result, we were able to further strengthen our balance sheet even in a challenging year with cash flow from operations totaling $1.5 billion, exceeding our capital spending. Production fell approximately two and a half percent from what we averaged in 2008.

We added a total of 79 million barrels of oil equivalent (MMBoe) of proven reserves from drilling, acquisitions and performance revisions, which represented 103 percent of 2009 production. These reserve additions were offset by negative revisions totaling 45 MMBoe due to price effects and new rules governing how proven undeveloped reserves are booked. We expect that the negative reserve revisions will be reversed in future years as prices return to more normal levels, and we execute our multi-year development programs.

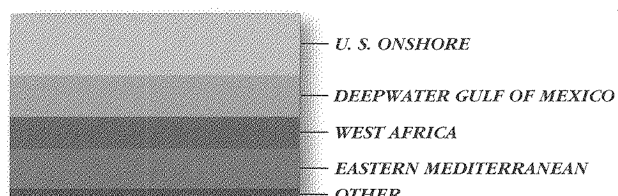
Our strategy is to create organic growth through exploration and development while remaining an opportunistic acquirer of assets. The balance and diversity of our portfolio continues to provide flexibility to better optimize the use of capital. Our key focus areas continue to be the U.S. onshore, the deepwater Gulf of Mexico, the Eastern Mediterranean and West Africa. All four of these areas have strong bases of existing production as well as deep inventories of investment opportunities. Because of the weak commodity environment, we chose to direct a sizable portion of our capital program into longer-term investments in 2009. It was not justified to invest in natural gas production due to low prices, especially in the U.S.

Onshore in the U.S., we prioritized investments to areas where we could benefit from improving liquid prices. In our Northern Region, we continued with an active drilling program in the Wattenberg field. At the beginning of 2010, we announced that we had entered into an agreement to purchase additional assets in Wattenberg and the surrounding DJ Basin. This acquisition, which closed in early March of 2010, will add an estimated 50 MMBoe of proven reserves and 10,000 barrels of oil equivalent per day of production. These assets contain several thousand drilling opportunities and fit in very nicely with our existing operations. We expect to double the production from these properties over the next two years. By the second half of 2010, we plan to have eight drilling rigs running in the Wattenberg field. Also onshore in the U.S. we continued an active

2009 RESERVES



2010 CAPITAL PROGRAM



program in the Cleveland Sands development program in Western Oklahoma. This area benefits from liquid production which improves drilling returns. Finally, in East Texas we formed a joint venture that allowed us to initiate drilling on our acreage located within the Haynesville shale play. Our first well was completed and showed strong production results. We expect to maintain an active drilling program in the Haynesville throughout 2010.

Our exploration program continued to deliver significant new resources to our portfolio. Over the past three years, we have discovered over 700 MMBoe of new resources, net to Noble Energy, through exploration. Most of these resources have not yet been recorded as proven reserves. In 2009, we made the largest discovery in our company's history at Tamar offshore Israel. Following the drilling and testing of two wells at Tamar, we announced that gross mean resources of the field were estimated to be approximately 6.3 trillion cubic feet of natural gas. Also in Israel in 2009, we made a second discovery at Dalit. We expect to continue with a very active exploration program in 2010 - perhaps our largest exploration program ever. We currently have seven significant wells scheduled for 2010 including five in the deepwater Gulf of Mexico, one in Equatorial Guinea and one in the Eastern Mediterranean.

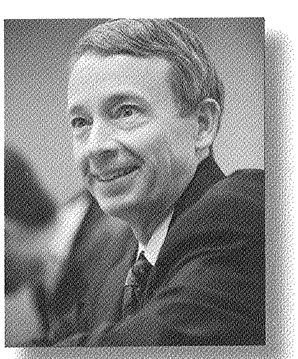
With a significant inventory of major exploration discoveries, we are quickly moving forward with plans for development. In 2009, we sanctioned Aseng in Equatorial Guinea and Galapagos in the deepwater Gulf of Mexico. Following the Tamar discovery, we quickly began assembling a project team charged with developing this huge discovery. By the end of the year, we announced two letters of intent (LOI) for gas sales from Tamar. Just these first two LOI's are expected to generate approximately $10 billion in gross sales revenues. Engineering and design work are moving forward rapidly, and we currently expect to sanction the development of Tamar in 2010.

We continue to make significant progress with our other major discoveries. In Equatorial Guinea, engineering work on the liquid-rich Belinda discovery has positioned us to potentially sanction this project in 2010. We are also evaluating additional projects that would ultimately allow us to produce and sell the natural gas from our West Africa discoveries. In the deepwater Gulf of Mexico, we plan to drill one or two appraisal wells at our Gunflint discovery. Gunflint was discovered in 2008 and represents our largest deepwater Gulf of Mexico exploration discovery to date.

The major exploration discoveries now under development are clearly positioning Noble Energy for significant future growth. Beginning in 2011 and continuing through the middle of the decade, we expect to have new production coming on stream from major projects nearly every year. Galapagos will be first in 2011 followed by Aseng and Tamar in 2012. Other major projects expected in the following years include Belinda, Diega and Carmen in West Africa and Gunflint in the Gulf of Mexico. The execution of these major projects is having a significant impact on our organization. We continue to recruit new employees who are experienced in designing and managing these technically challenging projects. We have formed a major projects organization that will keep us focused on best-in-class processes in support of our project execution. Our goal is to combine our best-in-class exploration results with best-in-class project execution in order to deliver maximum value to our shareholders.

It is more obvious than ever before that our success is dependent on the commitment and efforts of our employees. We continue to be successful in attracting high-quality talent to Noble Energy. All of our employees have done an amazing job in delivering results in a very challenging year. We all continue to focus on delivering superior returns to our shareholders while also assuring that the safety of everyone involved is preserved and impacts on the environment are minimized. We remain committed to helping the communities in which we live as we carry out our business.

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



Charles D. Davidson

Chairman of the Board
and Chief Executive Officer

OPERATING & FINANCIAL DATA - 2009 ANNUAL REPORT

OPERATING DATA

	2009	2008	2007	2006	2005
Year-End Proved Reserves					
Natural Gas (Bcf)	2,904	3,315	3,307	3,231	3,091
Liquids (MMBbls)	336	311	329	296	291
Total (MMBoe)	820	864	880	835	806
Sales Volumes					
Natural Gas (Bcf)	285	281	251	227	186
Liquids (MMBbls) [1]	29	32	31	30	22
Total (MMBoe)	77	79	73	68	53
Average Sales Price					
Natural Gas (per Mcf)	$ 2.54	$ 5.04	$ 5.26	$ 5.55	$ 5.78
Crude Oil and Condensate (per Bbl) [2]	$ 55.76	$ 82.60	$ 60.61	$ 54.47	$ 45.35

FINANCIAL DATA

(In millions, except per share amounts and ratios)

	2009	2008	2007	2006	2005
Revenues	$ 2,313	$ 3,901	$ 3,272	$ 2,940	$ 2,187
Net Income (Loss) [3]	$ (131)	$ 1,350	$ 944	$ 678	$ 646
Earnings (Loss) per Share Diluted	$ (0.75)	$ 7.58	$ 5.45	$ 3.79	$ 4.12
Weighted Average Shares Diluted	173	176	173	179	157
Cash Dividend per Share	$ 0.72	$ 0.66	$ 0.44	$ 0.28	$ 0.15
Net Cash Provided by Operating Activities	$ 1,508	$ 2,285	$ 2,017	$ 1,730	$ 1,240
Capital Expenditures [4]	$ 1,346	$ 2,264	$ 1,739	$ 1,347	$ 890
Total Assets	$ 11,807	$12,384	$10,831	$ 9,589	$ 8,878
Total Debt	$ 2,037	$ 2,266	$ 1,876	$ 1,801	$ 2,031
Stockholders' Equity	$ 6,157	$ 6,309	$ 4,809	$ 4,114	$ 3,090
Total Debt-to-Book-Capital Ratio	25%	26%	28%	30%	40%
Debt per BOE	$ 2.48	$ 2.62	$ 2.13	$ 2.16	$ 2.52

[1] Includes sales from equity method investees

[2] Excludes equity method investees

[3] See Adjusted Earnings and Reconciliation to Net Income (Loss) per the Company's quarterly earnings releases

[4] Excludes corporate acquisitions

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2009
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to
Commission file number: 001-07964

noble energy

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. ☒ Yes ☐ No

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

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

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

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

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

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2009: $10.1 billion.
Number of shares of Common Stock outstanding as of February 5, 2010: 174,444,080.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2010 Annual Meeting of Stockholders to be held on April 27, 2010, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2009, are incorporated by reference into Part III.

TABLE OF CONTENTS

PART I

Items 1. and 2. Business and Properties

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

General

Noble Energy, Inc. (Noble Energy, we or us) is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange (NYSE) since 1980. We are an independent energy company that has been engaged in the acquisition, exploration, development, production and marketing of crude oil, natural gas, and natural gas liquids (NGLs) since 1932. In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy and its subsidiaries. We operate primarily in the Rocky Mountains, Mid-continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel and West Africa.

Our aim is to achieve growth in earnings and cash flow through exploration success and the finding and development of a high quality portfolio of assets that is balanced between US and international projects. Exploration success, along with additional capital investment, in US and international locations such as Equatorial Guinea and Israel, have resulted in substantial growth in the last several years. In addition, occasional strategic acquisitions such as Patina Oil & Gas Corporation (Patina) in 2005 and U.S. Exploration Holdings, Inc. (U.S. Exploration) in 2006, combined with the sale of non-core assets, have allowed us to achieve a strategic objective of enhancing our asset portfolio, resulting in a company with assets and capabilities that include major US basins coupled with a significant portfolio of international properties. See Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2005-2009.

In the current commodity and economic environment, our focus has remained on positioning Noble Energy for the future. In January 2009, we announced a significant discovery at Tamar, offshore Israel, the largest discovery in our history. Also during 2009, we made substantial progress on our significant portfolio of long-term growth projects, including the sanctioning of the oil development projects at Aseng (formerly Benita) offshore Equatorial Guinea and at Isabela/Santa Cruz (which we refer to collectively as Galapagos) in the deepwater Gulf of Mexico, as well as making important progress on our plans for the Tamar discovery. These and other major development projects typically offer long life, sustained cash flows after investment and attractive financial returns. We also have significant remaining exploration potential, primarily in the deepwater Gulf of Mexico and offshore West Africa and Israel.

Major Development Project Inventory Our exploration success has provided us with a number of significant development projects on which we are moving forward. These projects will require significant capital investments over the next several years. Our major projects include the following:

- Galapagos (deepwater Gulf of Mexico);
- Aseng (offshore West Africa);
- Tamar (offshore Israel);
- Gunflint (deepwater Gulf of Mexico);
- Belinda (offshore West Africa); and
- Diega / Carmen (offshore West Africa).

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

Proved Oil and Gas Reserves Proved reserves estimates at December 31, 2009 were as follows:

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

	December 31, 2009		
	Proved Reserves		
	Crude Oil, Condensate & NGLs	Natural Gas	Total [1]
Reserves Category	(MMBbls)	(Bcf)	(MMBoe)
Proved Developed			
United States	122	1,114	307
Equatorial Guinea	49	638	155
Israel	-	191	32
Other International	23	192	56
Total Proved Developed Reserves	194	2,135	550
Proved Undeveloped			
United States	87	420	157
Equatorial Guinea	43	302	93
Israel	-	43	7
Other International	12	4	13
Total Proved Undeveloped Reserves	142	769	270
Total Proved Reserves	336	2,904	820

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

In December 2008, the Securities and Exchange Commission (SEC) announced that it had approved revisions to modernize its oil and gas company reserves reporting requirements. We adopted the new rules as of December 31, 2009. See Proved Reserves Disclosures, below, for additional disclosures provided in accordance with the SEC's rules for Modernization of Oil and Gas Reporting and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for definitions of proved oil and gas reserves, proved developed oil and gas reserves and proved undeveloped oil and gas reserves.

Crude Oil and Natural Gas Properties and Activities

We search for crude oil and natural gas properties, seek to acquire exploration rights in areas of interest and conduct exploratory activities. These activities include geophysical and geological evaluation and exploratory drilling, where appropriate, on properties for which we have acquired exploration rights. 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 advantage and which we believe offer superior returns. We have had substantial exploration success in the deepwater Gulf of Mexico, West Africa and the Eastern Mediterranean resulting in a significant portfolio of major development projects. We have numerous exploration opportunities remaining in these areas and are engaged in new venture activity in other international locations as well.

Appraisal, Development and Exploitation Activities We assess our exploration successes for potential development as demonstrated in our growing inventory of major projects. In 2009, we sanctioned the Isabela and Aseng projects and are progressing toward sanctioning the Tamar, Belinda and Gunflint projects during 2010 and/or 2011.We support a significant portion of the capital needs of these major projects with our long-lived inventory of low-risk development and exploitation projects. Low-risk development and exploitation projects, such as the Wattenberg field in our North America operations, also provide diversification and balance to our worldwide portfolio.

Acquisition and Divestiture Activities We maintain an ongoing portfolio optimization 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 divest non-core assets in order to optimize our property portfolio.

Pending Asset Acquisition In January 2010, we announced that we have entered into a definitive agreement to acquire substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for $494 million. We estimate total proved reserves to be 53 MMBoe, 45% of which are liquids and 80% are within the liquid-rich Wattenberg field, where our largest onshore US asset is located. The acquisition will add approximately 10 MBoepd, or 46 MMcf of natural gas and 2.5 MBbls of liquids to our daily production base, starting from the closing date, for 2010 and will provide significant growth potential. Included in the purchase are 340,000 total net acres, nearly 200,000 of which are located in the Greater Denver-Julesberg (DJ) Basin. The acquisition is expected to close late in the first quarter 2010 and is subject to customary closing conditions. See United States - Northern Region discussion below.

Mid-continent Acquisition In 2008, we acquired producing properties in western Oklahoma for $292 million. Properties acquired cover approximately 15,500 net acres. The total purchase price was allocated to the proved and unproved properties acquired based on fair values at the acquisition date. Approximately $254 million was allocated to proved properties and $38 million to unproved properties.

Sale of Argentina Assets In 2008, we closed on the sale of our producing property interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. The $24 million gain on sale was deferred until 2009 when approval was obtained from the Argentine government. Our crude oil reserves for Argentina totaled 7 MMBbls at December 31, 2007.

Sale of Gulf of Mexico Shelf Properties In 2006, we sold all of our significant Gulf of Mexico shelf properties except for the Main Pass area, which required repairs related to hurricane damage at the time. As of the effective date of the sale, proved reserves for the Gulf of Mexico properties sold totaled approximately 7 MMBbls of crude oil and 110 Bcf of natural gas. The deepwater Gulf of Mexico remains a core area and is more aligned with our long-term business strategies.

U.S. Exploration Acquisition In 2006, we acquired U.S. Exploration, a privately held corporation, for $412 million plus liabilities assumed. U.S. Exploration's reserves and production were located primarily in Colorado's Wattenberg field. This acquisition significantly expanded our operations in one of our core areas. Proved reserves of U.S. Exploration at the time of acquisition were approximately 234 Bcfe, of which 38% were proved developed and 55% natural gas. Proved crude oil and natural gas properties were valued at $413 million and unproved properties were valued at $131 million. In addition, we recorded $34 million of goodwill.

Patina Merger In 2005, we acquired Patina through merger (Patina Merger) for a total purchase price of $4.9 billion. Patina's long-lived crude oil and natural gas reserves provided a significant inventory of low-risk opportunities that balanced our portfolio. Patina's proved reserves at the time of acquisition were estimated to be approximately 1.6 Tcfe, of which 72% were proved developed and 67% natural gas. Proved crude oil and natural gas properties were valued at $2.6 billion and unproved properties were valued at $1.1 billion. In addition, we recorded $875 million of goodwill.

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. The Patina Merger and the acquisition of U.S. Exploration significantly increased the breadth of our onshore operations, especially in the Rocky Mountains and Mid-continent areas. These two acquisitions, along with other acquisitions of producing and non-producing properties, have provided us with a multi-year inventory of exploitation and development opportunities. We expect to close on a purchase of additional US Rocky Mountain assets in first quarter 2010, which will further increase our operations and project inventory in this area. In 2009, we were awarded 22 new leases in the deepwater Gulf of Mexico.

US operations accounted for 56% of our 2009 consolidated sales volumes and 56% of total proved reserves at December 31, 2009. Approximately 55% of the proved reserves are natural gas and 45% are crude oil, condensate and NGLs. Our onshore US portfolio at December 31, 2009 included 956,000 net developed acres and 1.3 million net undeveloped acres. We currently hold interests in 103 offshore blocks in the Gulf of Mexico.

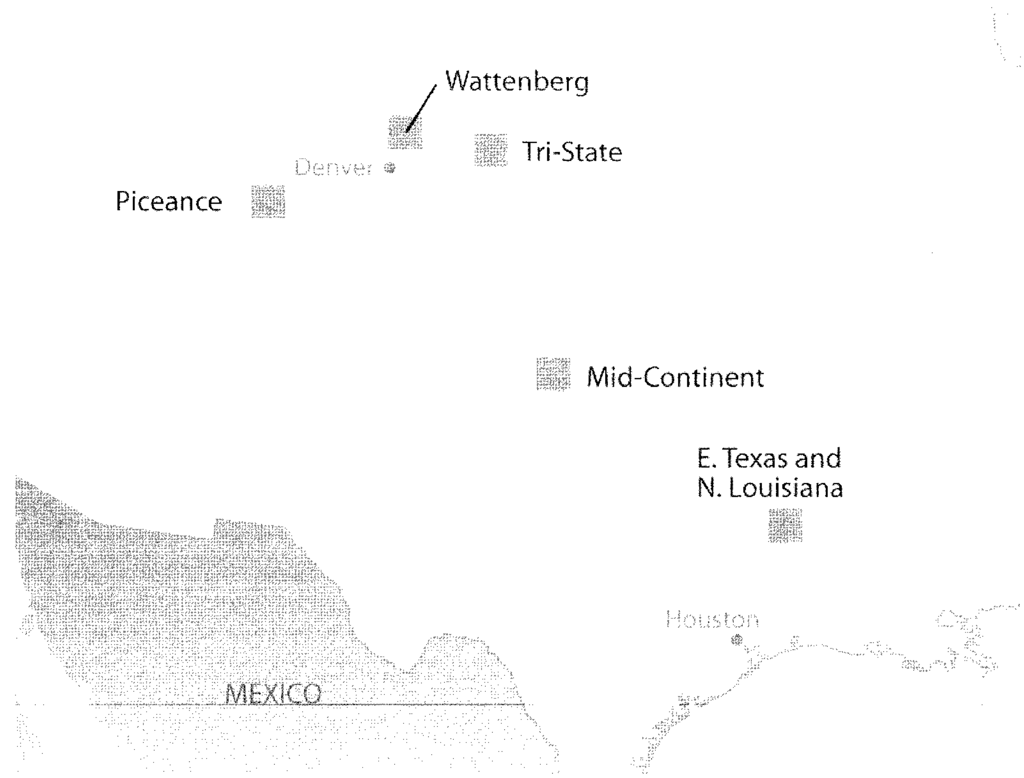
Sales of production and estimates of proved reserves for our significant US operating areas were as follows:

	Year Ended December 31, 2009				December 31, 2009		
	Sales Volumes				Proved Reserves		
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil, Condensate & NGLs	Natural Gas	Total
	(MBopd)	(MMcfpd)	(MBpd)	(MBoepd)	(MMBbls)	(Bcf)	(MMBoe)
Northern Region							
Wattenberg Field	15	150	6	46	129	819	266
Mid-continent Area	7	66	1	19	34	279	80
Other	-	95	-	16	1	290	49
Total	22	311	7	81	164	1,388	395
Southern Region							
Deepwater Gulf of Mexico	10	49	3	21	26	47	34
Other	5	37	-	11	19	99	35
Total	15	86	3	32	45	146	69
Total United States	37	397	10	113	209	1,534	464

Wells drilled in 2009 and productive wells at December 31, 2009 for our significant US operating areas were as follows:

	Year Ended December 31, 2009	December 31, 2009
	Gross Wells Drilled or Participated in	Gross Productive Wells
Northern Region		
Wattenberg Field	424	6,285
Mid-Continent Area	31	3,920
Other	145	2,648
Total	600	12,853
Southern Region		
Deepwater Gulf of Mexico	2	11
Other	32	1,180
Total	34	1,191
Total United States	634	14,044

Locations of our US onshore operations in the Wattenberg field, Mid-continent area and other significant areas are shown on the map below:



Northern Region The Northern region consists of our operations in the Rocky Mountain area, which includes the DJ (Wattenberg field), Piceance, San Juan, and Wind River basins, as well as the Niobrara (Tri-State) and Bowdoin fields. The Rocky Mountain area is one of our core operating assets. The Northern region also includes the Mid-continent area, consisting of properties in the Texas Panhandle, Oklahoma and Kansas.

Wattenberg Field The Wattenberg field (approximately 96% operated working interest), located in the DJ basin of north central Colorado, is our largest onshore US field and continues to grow. We acquired working interests in the Wattenberg field through the Patina Merger in 2005 and acquisition of U.S. Exploration in 2006. The Wattenberg field held 57% of our US proved reserves at December 31, 2009.

One of the most attractive features of the field is the presence of multiple productive formations, which include the Codell, Niobrara, and J-Sand formations, as well as the D-Sand, Dakota and the shallower Shannon, Sussex and Parkman formations. Drilling in the Wattenberg field is considered lower risk from the perspective of finding crude oil and natural gas reserves.

Our current field activities are focused primarily on the improved recovery of reserves through drilling new wells or deepening within existing wellbores, recompleting the Codell formation within existing J-Sand wells, refracturing or trifracturing existing Codell wells and refracturing or recompleting the Niobrara formation within existing Codell wells. A refracture consists of the restimulation of a producing formation within an existing wellbore to enhance production and add incremental reserves. A trifracture is effectively a refracture of a refracture. These projects and continued success with our production enhancement program, which includes well workovers, reactivations, and commingling of zones, allow us to increase production and add proved reserves to what is considered a mature field.

Due to economic conditions, our 2009 program decreased from 2008 levels. In 2009, we drilled or participated in 424 gross Wattenberg field development wells, with a 100% success rate. Three of these wells were horizontal wells targeting the Niobrara formation. We added approximately 36 MMBoe of proved reserves, approximately 49% of which were natural gas. At year-end, we were running five drilling rigs and 17 completion units in the field.

We have experienced significant growth in production from the Wattenberg field, from an average of 33 MBoepd at year-end 2005 to approximately 45 MBoepd for fourth quarter 2009. Expansion of field boundaries has resulted in a large increase in our crude oil and NGL stream since year-end 2005. As a result, year-end 2009 production included approximately 20 MBpd of liquids. Sales of Wattenberg field production accounted for 41% of total US sales volumes in 2009.

The infrastructure in this area is improving and expanding. Oil transport alternatives improved in 2009 with the start up of a new interstate crude oil transportation pipeline system running from Weld County, Colorado, where the

Wattenberg field is located, to Cushing, Oklahoma. The pipeline, in which we own a small equity interest, provides another option for the marketing of our crude oil. We have a five-year throughput agreement with the pipeline.

We continue to acquire acreage in the area and held interests in approximately 350,000 net acres at year-end 2009. We are planning an active capital program in 2010 and expect to increase the program from 2009 levels, drilling approximately 500 wells, with continued focus on new wells in the Codell/Niobrara formations. We will have the flexibility with short-term drilling rig contracts to decrease activity if economic conditions decline. Additionally, we have a substantial project inventory remaining and plan to continue steady refracture, trifracture, and recompletion programs in 2010.

As discussed under Acquisition and Divestiture Activities – Pending Asset Acquisition above, we expect to close on an acquisition of additional US Rocky Mountain assets late in the first quarter 2010. We have identified several thousand projects associated with the assets being acquired, including over 2,000 Codell/Niobrara drilling locations in Wattenberg. We plan to add two rigs to our Wattenberg program in 2010 as a result of the transaction. We expect this activity to grow net production, with a focus on increasing liquids contribution.

Mid-continent Area The Mid-continent area includes properties in the Texas Panhandle, Oklahoma and Kansas. Significant areas of activity have been in the Cleveland Sandstone area of western Oklahoma (89% operated working interest). We drilled or participated in 31 development wells in 2009, 97% of which were successful.

In 2009, we continued drilling in the Cleveland Sandstone formation in western Oklahoma, on acreage we acquired in 2008. Cleveland Sandstone is a tight gas play characterized by low-permeability rock. We drilled 20 wells (included in the count above) using horizontal drilling techniques, all of which were successful, and recent wells have come on line with greater than 40% liquids production. We currently have one rig operating and expect to drill approximately the same number of wells in 2010 as we drilled in 2009.

Other Northern Region Other Northern region areas of activity are as follows:

Piceance Basin – The Piceance basin in western Colorado (approximately 89% operated working interest) is a major North America natural gas basin and is characterized by low-porosity rock. The primary productive formation is the Mesaverde Williams Fork formation. Multiple wells are drilled from individual drilling pads to reduce rig mobilization costs in mountainous terrain and to minimize environmental impact on the surface area. Well spacing is approximately ten acres per well.

As in the Wattenberg field, Piceance basin drilling time per well has been reduced due to our increased use of improved drilling technology. In the Piceance basin, we are using new fit-for-purpose rigs which include design innovations and technology improvements that capture incremental time savings during all phases of the well drilling process, including moving between wells. Fit-for-purpose rigs can drill multiple wells from one location and are particularly useful in developing hydrocarbon reserves in tight-gas areas such as the Piceance basin.

In 2009, we drilled or participated in 48 development wells and one exploratory well, 100% of which were successful. Successful drilling activity in recent years has led to significant volume growth; production has grown from 2 MMcfepd in 2005 to 54 MMcfepd for fourth quarter 2009.

We have assembled a significant acreage position in the Piceance basin and currently hold interests in approximately 20,000 net acres providing a large inventory of future projects. At this time, we plan to operate a single-rig drilling program in 2010.

Tri-State Area (Niobrara) – Our operations in the Tri-State area (eastern Colorado, extending into Kansas and Nebraska) center primarily around the development of the Niobrara Trend (approximately 96% operated working interest). The Niobrara formation is an important shallow natural gas producer. Since 2006, we have expanded our acreage position to over 580,000 net acres. We have a substantial future project inventory, including Niobrara infill and exploitation drilling along with gathering system and compressor station additions to develop reserves and deliver new production. In 2009, we drilled or participated in 64 development wells, 100% of which were successful, and we plan to continue our Niobrara drilling program in 2010.

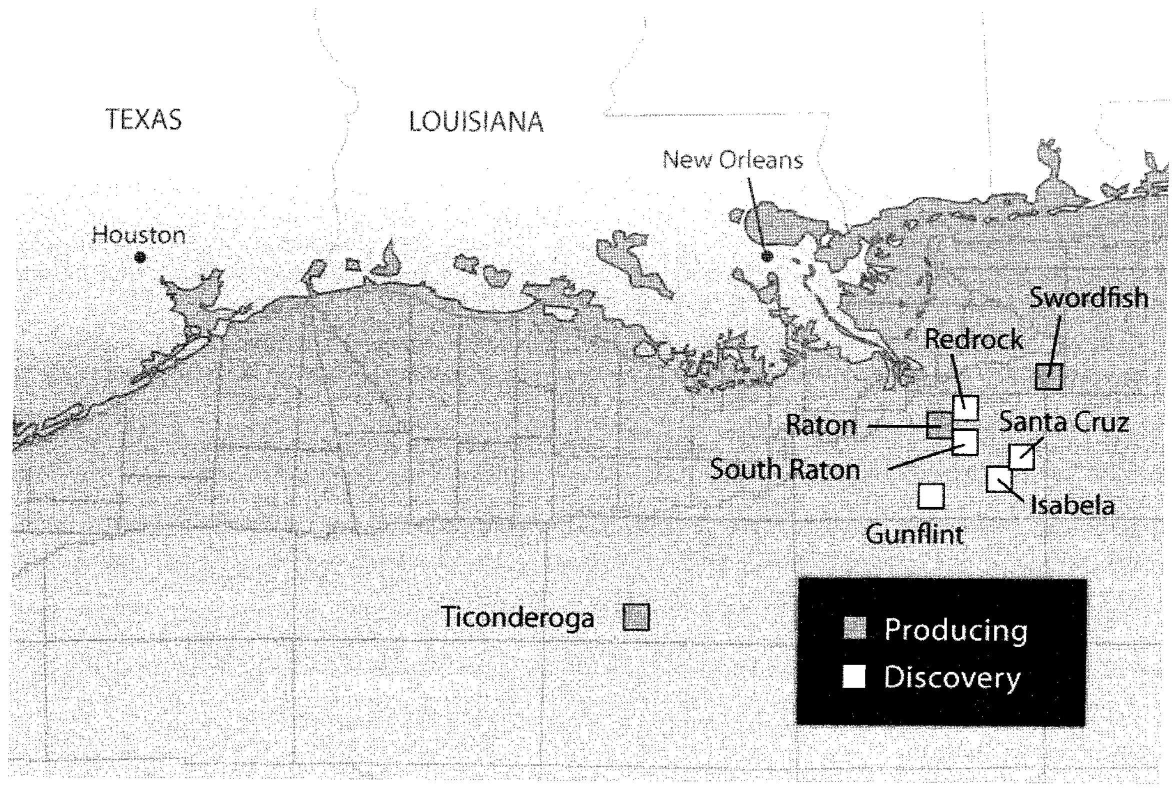
Wind River Basin – At Iron Horse in the Wind River Basin (88% operated working interest) located in central Wyoming, we drilled 18 development wells during 2009 with a 94% success rate. We plan to continue our drilling program here during 2010 and expect to drill approximately 20 new wells.

Bowdoin and San Juan – We are also active in the Bowdoin field (approximately 63% operated working interest), located in north central Montana and the San Juan basin (approximately 82% operated working interest), located in northwestern New Mexico and southwestern Colorado. In 2009, activity was reduced in these areas as we focused most of our capital spending on the core development fields of Wattenberg, Piceance and western Oklahoma. We drilled or participated in a total of 13 development wells in the Bowdoin field and San Juan basin, 100% of which were successful, and one unsuccessful exploratory well.

Southern Region The Southern region includes the deepwater Gulf of Mexico and onshore areas primarily in Texas and Louisiana.

Deepwater Gulf of Mexico The deepwater Gulf of Mexico is one of our core areas and accounted for 19% of 2009 US sales volumes and 7% of US proved reserves at December 31, 2009. We currently hold leases on 103 deepwater

Gulf of Mexico blocks, representing approximately 390,000 net acres. We operate approximately 86% of the leases. Locations of our deepwater Gulf of Mexico developments are shown on the map below:



We continue to expand our deepwater Gulf of Mexico operations primarily through an active exploration program, expansion of our 3-D seismic database, and lease acquisition. Our exploration activities have led to discoveries at Gunflint, a 2008 discovery which is our largest deepwater Gulf of Mexico discovery to date; Isabela; Redrock/Raton; and, most recently, Santa Cruz.

During 2009, we moved forward with development plans for some of our recent discoveries, as discussed below, and continued our exploratory program. We participated in Central Gulf of Mexico Lease Sale 208 and were awarded 22 new deepwater Gulf of Mexico blocks which will complement our growing inventory of exploration opportunities. We currently have an inventory of over 30 identified prospects, with a combination of both large stand-alone prospects as well as a number of smaller, tie-back opportunities.

Our exploration efforts continued during December 2009 as drilling began on two significant test wells at the Deep Blue prospect (Green Canyon Block 723; 33.75% operated working interest) and one at the Double Mountain prospect (Green Canyon Block 556; 30% non-operated working interest).

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

Gunflint (Mississippi Canyon Block 948; 37.5% operated working interest and Mississippi Canyon Block 949; 43.75% operated working interest) We announced the Gunflint crude oil discovery, our largest deepwater Gulf of Mexico discovery to date, in October 2008. We have acquired additional seismic information and are preparing to drill one or two appraisal wells in 2010. We are the operator of the development.

Galapagos Development Project including Isabela (Mississippi Canyon Block 562, 33% non-operated working interest) and Santa Cruz (Mississippi Canyon Blocks 519/563, 23.25% operated working interest) During third quarter 2009, we approved the Galapagos development project, which consists of our 2007 discovery, Isabela, and our 2009 discovery on adjacent acreage, Santa Cruz. The phased development plan includes completion of the Isabela and Santa Cruz wells during second and third quarter 2010, and then connecting them to nearby infrastructure via subsea tiebacks. Initial production is expected in 2011. During the first half of 2010, we also plan to drill the Santiago exploration well (23.25% operated working interest) which is a separate prospect in the same offshore block as Santa Cruz. If the Santiago well is successful, it will be completed in 2010, with production expected in 2011.

Redrock/Raton (Mississippi Canyon Blocks 204, 248 and 292; 66.67 % working interest) Redrock was a 2006 natural gas/condensate discovery and Raton was a 2006 natural gas discovery. The South Raton appraisal well was also drilled in 2006. In 2007, we successfully sidetracked and completed the Raton discovery well and it was tied back and came on production in late 2008. In 2008, we drilled a successful sidetrack-appraisal well at South Raton and we currently expect it to be tied back to a host facility. Redrock is currently considered a co-development candidate to the completed sidetrack well at South Raton. We are the operator of Redrock/Raton.

Swordfish (Viosca Knoll Blocks 917, 961 and 962; 85% working interest) Swordfish was a 2001 discovery and began producing in 2005. During 2009, a Swordfish gas well watered out. We sidetracked the well into an oil zone, and production began in January, 2010. The Swordfish project currently includes three producing wells connected to a third-party production facility through subea tiebacks. We are the operator of Swordfish.

Ticonderoga (Green Canyon block 768; 50% working interest) Ticonderoga is a non-operated 2004 crude oil discovery and began producing in 2006. The project currently includes three producing wells connected to existing infrastructure through subea tiebacks. In September 2008, Ticonderoga was shut-in as a result of hurricane damage to third-party processing and pipeline facilities. It remained shut-in until August 2009 when it was returned to full production.

Onshore East Texas and North Louisiana This is an emerging area for us. Recent acquisitions have increased our leasehold acreage to approximately 17,000 gross acres. Our 2009 drilling program targeted the Haynesville shale (approximately 60% working interest), and we completed our first horizontal East Texas Haynesville shale well with an initial thirty-day average production rate of over 11 MMcfpd, gross. We drilled a second exploration well in fourth quarter 2009 that was completed in late January 2010 and is being tested. We plan to drill approximately 10 to 11 Haynesville wells on our operated acreage in 2010 and participate in another seven to eight Haynesville wells operated by others.

International

International operations are significant to our business, accounting for 44% of consolidated sales volumes in 2009 and 44% of total proved reserves at December 31, 2009. International proved reserves are approximately 64% natural gas and 36% crude oil. Operations in Equatorial Guinea, Ecuador, China and Suriname are conducted in accordance with the terms of production sharing contracts. In Cameroon, we operate in accordance with the terms of a production sharing contract and a mining concession. Operations in the North Sea, Israel and other foreign locations are conducted in accordance with concession agreements or licenses.

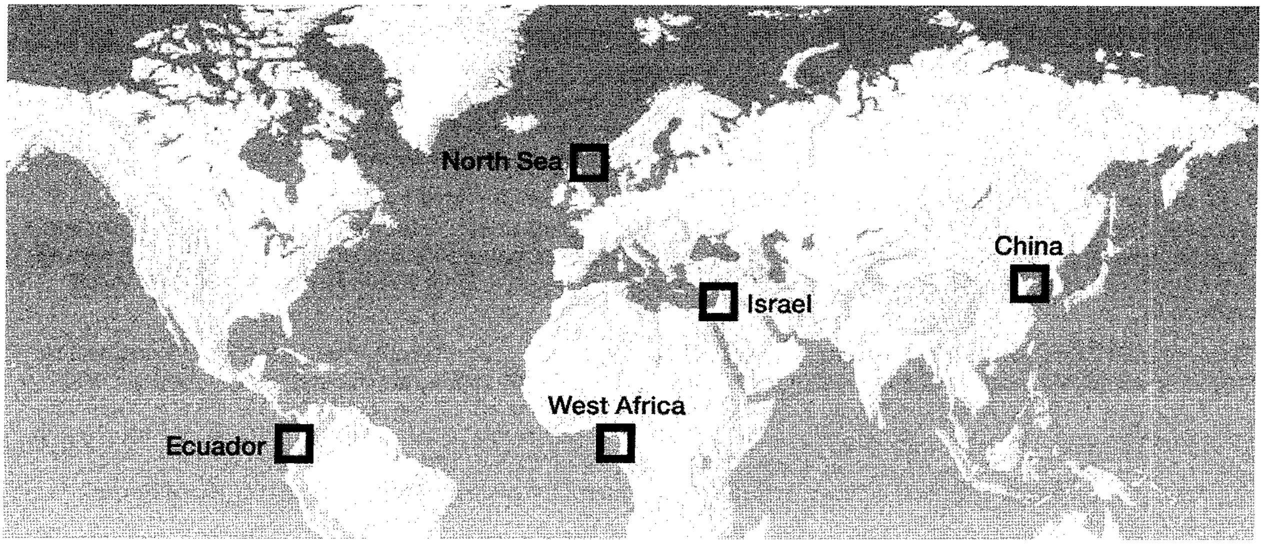
Sales of production and estimates of proved reserves for our significant international operating areas are as follows:

	Year Ended December 31, 2009				December 31, 2009		
	Sales Volumes				Proved Reserves		
	Crude Oil & Condensate	Natural Gas	NGL's	Total	Crude Oil, Condensate & NGLs	Natural Gas	Total
	(MBopd)	(MMcfpd)	(MBpd)	(MBoepd)	(MMBbls)	(Bcf)	(MMBoe)
International							
Equatorial Guinea	14	239	-	54	92	940	248
Israel	-	114	-	19	-	234	39
Other	11	31	-	16	35	196	69
Total International	25	384	-	89	127	1,370	356
Equity Investee	2	-	6	8	-	-	-
Total	27	384	6	97	127	1,370	356
Equity Investee Share of Methanol Sales (MMgal)				145			

Wells drilled in 2009 and productive wells at December 31, 2009 in our international operating areas were as follows:

	Year Ended December 31, 2009	December 31, 2009
	Gross Wells Drilled or Participated in	Gross Productive Wells
International		
Equatorial Guinea	1	24
Israel	3	5
North Sea	6	30
Ecuador	-	3
China	1	16
Total International	11	78

Locations of our major international operations are shown on the map below:



West Africa (Equatorial Guinea and Cameroon) West Africa is one of our core operating areas. Crude oil and natural gas sales volumes accounted for 61% of 2009 consolidated international sales volumes and 70% of international proved reserves at December 31, 2009. At December 31, 2009, we held approximately 53,000 net developed acres and 212,000 net undeveloped acres in Equatorial Guinea and 563,000 net undeveloped acres in Cameroon.

Alba Field We began investing in West Africa in the early 1990's. Activities center around our 34% non-operated working interest in the Alba field, offshore Equatorial Guinea, which is one of our most significant assets. Operations include the Alba field and related production and condensate facilities, a methanol plant, and an onshore LPG processing plant (both located on Bioko Island) where additional condensate is produced. The methanol plant is capable of producing up to 3,000 MTpd gross.

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 by the equity method. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest accounted for by the equity method. The methanol plant purchases natural gas from the Alba field under a contract that runs through 2026. AMPCO subsequently markets the produced methanol 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 and from the LPG plant under short-term contracts at market-based prices.

Blocks O and I, YoYo and Tilapia During the past several years, we have conducted a successful exploration and appraisal drilling program in the Douala basin in West Africa, centering around Blocks O and I, offshore Equatorial Guinea, and the YoYo mining concession and Tilapia production sharing contract offshore Cameroon, where we have an interest in over 1.1 million gross acres. We are the operator in Cameroon (50% working interest) and the technical operator on Block O (45% working interest) and Block I (40% working interest).

Our first discovery occurred in October 2005, when we announced successful test results from the O-1 (Belinda) exploration well offshore Equatorial Guinea. In 2007, we drilled seven wells, resulting in three new discoveries and three successful appraisal wells. In 2008, we announced successful results from the I-5 Benita oil appraisal well on Block I; the Felicita, a condensate and natural gas discovery on Block O; and the Diega, a gas condensate and oil discovery on Block I. In February 2009, we announced a successful oil discovery on Block O at the Carmen prospect.

In December 2008, we submitted a Plan of Development for the Aseng field (formerly known as Benita) to the government of Equatorial Guinea. On July 22, 2009, we announced that it had been sanctioned by us, our partners, and the Ministry of Mines, Industry, and Energy of the Republic of Equatorial Guinea.

Initial development of the Aseng field will include multiple subsea wells flowing to a floating production, storage and offloading vessel (FPSO) where the production stream will be separated. The oil will be stored on the FPSO until sold, while the natural gas and water will be reinjected into the reservoir to maintain pressure and maximize oil recoveries. The FPSO is designed with capacity to process 120 MBpd of liquids, including 80 MBpd of oil. In addition, the vessel will be capable of reinjecting 170 MMcfpd of natural gas. Storage on the vessel will be approximately 1.6 MMBbls of liquids. The vessel is designed to act as an oil production hub, and as a liquids storage and offloading hub with capabilities to support future subsea oil field developments, and capabilities to take on board, independently from the production train, stabilized condensate from gas condensate fields in the area. First production from the Aseng field is estimated to commence by mid-year 2012 at 50 MBpd of oil gross (16.5 MBpd net). The FPSO and subsea equipment contracts were awarded in 2009, and construction activities have begun on the FPSO. We have two rigs contracted to assist in field development. Drilling and completion activities have commenced.

We have evaluated the potential for additional liquids and gas projects, and expect that the next development will be at the Belinda field. We are engaged in geologic and reservoir FEED (front end engineering design) work at Belinda, targeting liquid production from this gas condensate field. We currently anticipate drilling subsea wells which will be tied to a production facility that would remove liquids and reinject gas for future use pending further development at Belinda. The liquids would be transported to the FPSO at Aseng for storage and sales. Belinda project sanction is currently scheduled to occur in 2010 with production beginning in 2013. We are also evaluating future oil projects at Diega and Carmen and currently scheduling first production for 2014.

In 2010, we expect to resume exploration activities offshore Equatorial Guinea and acquire a 3-D seismic survey over YoYo and portions of Tilapia in Cameroon.

Eastern Mediterranean (Israel and Cyprus) Another core operating area is located offshore Israel. Natural gas sales volumes in Israel accounted for 21% of 2009 consolidated international sales volumes and natural gas reserves accounted for 11% of international proved reserves at December 31, 2009. At December 31, 2009, we held approximately 29,000 net developed acres and 796,000 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 17 licenses. We are the operator of the properties. We also hold a license covering approximately 795,000 net undeveloped acres offshore Cyprus.

Mari-B Field We have been operating in the Mediterranean Sea, offshore Israel, since 1998, and the Mari-B field (47% working interest) is one of our core international assets. The Mari-B field is the first offshore natural gas production facility in Israel and currently has a peak deliverability of approximately 500 MMcfpd from five wells. In 2008, we commissioned a permanent onshore receiving terminal in Ashdod for distribution of natural gas from the Mari-B field to purchasers. During 2009, we moved forward on a compression project that we expect will recover additional reserves and extend the field's peak deliverability. We also began mobilizing equipment to drill two development wells planned in the first half of 2010. Together with the completion of the compression work, these new wells will provide substantial, additional near-term gas deliverability and serve as injection wells for natural gas storage in the future.

Natural gas sales began in 2004 and have increased steadily as Israel's natural gas infrastructure has developed. Average sales volumes have risen from 48 MMcfpd in 2004 to a record high of 139 MMcfpd in 2008 and were 114 MMcfpd in 2009. The natural gas market in Israel continues to be robust. The Israel Electric Corporation Limited (IEC), our largest purchaser, has continued to convert power plants to use natural gas as fuel. In 2009, the IEC power plant at Hagit began consuming natural gas purchased from us and in December 2009 we initiated natural gas sales to a new customer, Israel Chemicals Ltd.

During third quarter 2009, we signed a new natural gas sales contract with our primary customer, IEC, under the terms of which they will purchase the majority of our remaining undedicated Mari-B field gas at prices expected to be significantly higher than what we have been receiving under the original contract. The actual price received is tied to a blend of liquids prices and a producer price index. In addition, it was agreed that all sales from the Mari-B field going forward will be proportionately allocated between the two contracts regardless of the total volume sold. This is a major change from the past arrangement wherein only "excess" volumes above a threshold level received premium prices. In addition, we have signed a letter of intent (LOI) with IEC, under which IEC expects to purchase natural gas to establish a strategic inventory reserve at Mari-B. The Mari-B partners would provide IEC with injection, storage and withdrawal capabilities for this inventory under a related service agreement.

Competing imports of natural gas from Egypt to Israel began in 2008. However, there is still opportunity for significant new sales in the future as the Israeli infrastructure and markets continue to expand.

Tamar and Dalit During 2009, our exploratory program resulted in two significant discoveries. In January 2009, we announced a very significant natural gas discovery at the Tamar-1 well at the Tamar prospect (36% working interest), offshore northern Israel, and in February 2009, we announced a successful test of production flow rates at the location. Then in March 2009, we announced another natural gas discovery at the Dalit prospect (36% working interest) followed by a successful well test in April 2009.

We then drilled a Tamar appraisal well (Tamar-2), the results of which increased our estimate of the size of the reservoir and confirmed its high quality and extent. Tamar is the largest discovery in our history.

We are moving forward with Tamar development plans, and expect project sanction and recording of proved reserves in the first half of 2010, with first production projected for 2012.

In fourth quarter 2009, we signed an LOI to sell natural gas from the Tamar field to Dalia Power Energies (Dalia). Dalia, a privately-owned electricity company, has a license to build a natural gas-fired power plant in Israel with operations planned to commence in 2013. According to terms of the LOI, we and our partners will deliver natural gas volumes of approximately 200 Bcf to Dalia under a 17-year supply agreement. Sales volumes under the LOI may be increased to 700 Bcf depending upon the final size of the power plant and extent of operations. We also signed an LOI to sell natural gas from the Tamar field to IEC. IEC expects to purchase at least 95 Bcf of natural gas per year with the potential to procure significantly higher quantities for a period of 15 years beginning at the startup of Tamar.

We continue to remain focused on the vast exploration potential remaining offshore Israel. The successes at Tamar and Dalit opened up a substantial new natural gas basin, the Levantine. A 3-D seismic program is underway to collect additional data over several leads on our acreage in the Levantine. Based on results from the seismic program, we are planning to drill an exploratory well in the area in the second half of 2010.

Other

North Sea We have been conducting business in the North Sea (the Netherlands and the UK) since 1996 and currently have working interests in 18 licenses with working interests ranging from 7% to 40%. We are the operator of one block. The North Sea accounted for 8% of 2009 consolidated international sales volumes and 7% of international proved reserves at December 31, 2009. At December 31, 2009, we held approximately 6,000 net developed acres and 44,000 net undeveloped acres.

Most of our production is from the non-operated Dumbarton field (30% working interest) in blocks 15/20a and 15/20b in the UK sector of the North Sea. We also produce 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 in which we own a 30% interest. Additional development (30% working interest) began in 2008, and two new wells were brought on line. During 2009, our field optimization work continued. Dumbarton now has eight horizontal producers and two water injection wells.

The Dumbarton field experienced a controlled shut-down in August 2009, due to a malfunctioning swivel on the FPSO. Production was deferred for essentially all of September and October.

We also participated in the development of the nearby Lochranza discovery in block 15/20a (30% working interest). During 2009, the first Lochranza horizontal well was completed and tied back to Dumbarton's subsea facilities. Production began in fourth quarter 2009. We expect a second horizontal well to be completed and come on line in the first quarter of 2010.

We have also participated in the Flyndre project (22.5% working interest) and Selkirk project (30.5% working interest), both located in the UK sector of the North Sea. At Flyndre, we successfully completed an exploratory appraisal well in 2007. We are currently working with the project operator and other partners to finalize the field development plan and relevant operating agreements. At Selkirk, we participated in the drilling of an appraisal well which was sidetracked to the original discovery well location, to ensure presence of effective reservoir, and suspended as a future producer. We are currently working with our partners on development options.

In 2009, we conducted a market test of our wholly-owned subsidiary Noble Energy (Europe) Limited, which holds our interests in the Netherlands and the UK, and received bids. However, we have not committed to a plan to sell these assets.

Ecuador Operations in Ecuador accounted for 5% of 2009 consolidated international sales volumes and 8% of international proved reserves at December 31, 2009. The concession covers approximately 12,000 net developed acres and 849,000 net undeveloped acres.

We have been operating in Ecuador since 1996. We utilize natural gas from the Amistad field (in shallow water offshore Ecuador) to generate electricity through a 100%-owned natural gas-fired power plant, located near the city of Machala. The Machala power plant, which began operating in 2002, is a single cycle generator with a capacity of 130 MW from twin turbines. It is the only natural gas-fired commercial power generator in Ecuador and currently one of the lowest cost producers of thermal power in the country. The Machala power plant connects to the Amistad field via a 40-mile pipeline. In 2009, power generation totaled 902 GW hours.

See Risk Factors – *Our operations and investment in Ecuador may be adversely affected by the country's unsettled economic and political environment* and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Current Conditions in Ecuador.

China We have been engaged in exploration and development activities in China since 1996, with production beginning in 2003. We have a 57% working interest in the Cheng Dao Xi (CDX) field, which is located in the shallow water of the southern Bohai Bay. During fourth quarter 2009, we drilled one horizontal well from our existing platform at the CDX field and commenced drilling a second well. The rig will initiate a program to pre-drill a number of production and injection wells designed to be connected to a second platform at the field. This is part of the ongoing expansion project with plans to install the second platform and connect the additional wells in late 2010. China accounted for 5% of 2009 consolidated international sales volumes and 4% of international proved reserves at December 31, 2009. At December 31, 2009, we held approximately 4,000 net developed acres and no undeveloped acres.

Additional International Locations We hold approximately four million net undeveloped acres in other international locations including Suriname, Nicaragua, and India.

Proved Reserves Disclosures

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. The most significant amendments to the requirements included the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows are now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserves Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- Reserves Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Disclosure by Geographic Area – Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and gas proved reserves.
- Non-Traditional Resources – The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009.

Effect of Adoption Application of the new reserve 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 new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 27 MMBoe. Use of the old year-end prices 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 rules resulted in negative reserves revisions of 61 MMBoe. In addition to the new pricing methodology rules, the new proved undeveloped reserves rules, which limit PUDs to those scheduled to be drilled within the next five years, resulted in an additional reduction of proved reserves of approximately 18 MMBoe.

Internal Controls Over Reserves Estimates Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. Responsibility for compliance in reserves bookings is delegated to our Corporate Reservoir Engineering group and requires that reserves estimates be made by the regional reservoir engineering staff and reviewed by the regional reservoir engineering supervisor.

Qualified petroleum engineers in our Houston, Denver and London 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 20 years of industry experience with positions of increasing responsibility in engineering and evaluations. The Vice President – Reserves reports directly to our Chief Executive Officer.

We engage a third-party petroleum consulting firm to audit a significant portion of our reserves. See Third-Party Reserves Audit below.

Technologies Used in Reserves Estimation The SEC's new 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 2009 reserves estimates.

Third-Party Reserves Audit In each of the years 2009, 2008 and 2007, we retained Netherland, Sewell & Associates, Inc. (NSAI), independent, third-party reserves engineers, to perform reserves audits of proved reserves. The reserves audit for 2009 included a detailed review of 20 of our major international, deepwater Gulf of Mexico and US onshore fields, which covered approximately 78% of US proved reserves and 96% of international proved reserves (86% of total proved reserves). The reserves audit for 2008 included a detailed review of 18 of our major fields and covered approximately 86% of total proved reserves. The reserves audit for 2007 included a detailed review of 16 of our major fields and covered approximately 81% of total proved reserves.

In connection with the 2009 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 producing 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 the recently updated 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 conform to the guidelines 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)(2) of Regulation S-X. NSAI issued an unqualified audit opinion on our proved reserves at December 31, 2009, based upon its evaluation. The NSAI opinion concluded that our estimates of proved reserves were, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. NSAI's report is attached as Exhibit 99.2 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 Board of Directors. 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. On a quantity basis, the NSAI field estimates ranged from one MMBoe above to 16 MMBoe below as compared with our estimates. On a percentage basis, the NSAI field estimates ranged from 9% above our estimates to 20% below our estimates. 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, 2009 were, in the aggregate, approximately 21 MMBoe, or 3%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2009, our PUDs totaled 142 MMBbls of crude oil and 769 Bcf of natural gas, for a total of 270 MMBoe.

PUD Locations Approximately 70% of our PUDs at year-end 2009 were associated with our major development areas in the Wattenberg field (onshore US) and the Alba field (offshore Equatorial Guinea). An additional 17% of PUDs at year-end 2009 were associated with major development projects at the Aseng field (offshore Equatorial Guinea) and the Galapagos project (deepwater Gulf of Mexico). All of these projects will have PUDs convert from undeveloped to developed as these projects begin production and/or production facilities are expanded or upgraded.

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

- conversion of approximately 23 MMBoe PUDs into proved developed reserves;
- reclassification of approximately 18 MMBoe PUDs that were not scheduled to be developed within five years from proved to probable reserves; and
- negative revisions of approximately 23 MMBoe in PUDs due to changes in commodity prices.

The majority of the reserves reclassified from proved reserves to probable reserves were associated with the Wattenberg field, where we maintain an extensive multi-year development program.

Development Costs Costs incurred relating to the development of PUDs were approximately $440 million in 2009, $528 million in 2008 and $390 million in 2007.

Estimated future development costs relating to the development of PUDs are projected to be approximately $900 million in 2010, $800 million in 2011, and $500 million in 2012.

Drilling Plans All PUD drilling locations are scheduled to be drilled prior to the end of 2014. 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 2014. Initial production from these PUDs is expected to begin between 2010 to 2015.

We have 7 MMBoe of PUDs associated with an international discovery that has been booked for longer than five years. Development planning is proceeding on this project, and drilling is expected to begin in the next two years. The only other PUDs that have been booked for longer than five years are associated with compression projects. In those cases, the reserves are expected to be recovered from existing wells.

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;

- 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, 2009, no crude oil or natural gas reserves information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (EIA) of the US Department of Energy. We file Form 23, including reserves and other information, with the EIA.

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

	Sales Volumes			Average Sales Price			Production Cost [1]
	Crude Oil MBpd	Natural Gas MMcfpd	NGLs MBpd	Crude Oil Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per BOE
Year Ended December 31, 2009							
United States							
Wattenberg Field	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 [2]	37	397	10	55.19	3.61	27.96	6.26
Alba Field (Equatorial Guinea) [3]	14	239	-	55.94	0.27	-	2.30
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 [4]	2	-	6	59.51	-	36.03	
Total	64	781	16	$ 55.87	$2.54	$31.20	
Year Ended December 31, 2008							
United States							
Wattenberg Field	15	146	5	$ 71.41	$ 7.39	$52.19	$ 3.12
Other US	25	249	4	78.02	8.55	$47.51	7.91
Total US [2]	40	395	9	75.53	8.12	$50.15	6.08
Alba Field (Equatorial Guinea) [3]	15	206	-	88.95	0.27	-	2.17
Israel	-	139	-	-	3.10	-	1.07
North Sea	10	5	-	100.56	10.54	-	12.63
Ecuador	-	22	-	-	-	-	-
China	4	-	-	82.66	-	-	7.03
Total Consolidated Operations	69	767	9	82.60	5.04	50.15	$4.90
Equity Investee [4]	2	-	6	96.77	-	58.81	
Total	71	767	15	$ 82.96	$ 5.04	$53.45	
Year Ended December 31, 2007							
United States							
Wattenberg Field	13	163	-	$ 68.19	$ 5.52	$ -	$ 2.68
Other US	29	249	-	46.76	8.82	-	6.72
Total US [2]	42	412	-	53.22	7.51	-	5.26
Alba Field (Equatorial Guinea) [3]	15	132	-	71.27	0.29	-	2.89
Israel	-	111	-	-	2.79	-	1.14
North Sea	13	6	-	76.47	6.54	-	7.68
Ecuador	-	26	-	-	-	-	-
China	4			58.79			7.08
Argentina [5]	3	-	-	46.79	-	-	11.79
Total Consolidated Operations	77	687	-	60.61	5.26	-	$4.62
Equity Investee [4]	2	-	6	74.87	-	48.87	
Total	79	687	6	$ 60.94	$ 5.26	$48.87	

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

(2) Average crude oil sales prices reflect reductions of $2.13 per Bbl (2009), $22.06 per Bbl (2008), and $13.68 per Bbl (2007) from hedging activities. Average natural gas sales prices reflect increases of $0.23 per Mcf (2008),

and $1.12 per Mcf (2007) from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis.

(3) Average crude oil sales prices reflect reductions of $5.57 per Bbl (2009), $7.59 per Bbl (2008), and $2.19 per Bbl (2007) from hedging activities. 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.

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

(5) We sold our Argentina assets in February 2008.

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

At December 31, 2009, our operated properties accounted for approximately 60% 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, 2009 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States						
Northern Region	7,825	6,119.0	5,028	3,637.9	12,853	9,756.9
Southern Region	799	593.0	392	175.0	1,191	768.0
Equatorial Guinea	4	1.7	20	7.7	24	9.4
Israel	-	-	5	2.4	5	2.4
North Sea	22	4.7	8	1.0	30	5.7
Ecuador	-	-	3	3.0	3	3.0
China	15	8.6	1	0.6	16	9.2
Total	8,665	6,727.0	5,457	3,827.6	14,122	10,554.6

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, 2009 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands)				
United States				
Onshore	1,625	956	1,603	1,262
Offshore	134	84	524	362
Total United States	1,759	1,040	2,127	1,624
International				
Equatorial Guinea	140	53	523	212
Cameroon	-	-	1,125	563
Israel	62	29	1,790	796
North Sea (1)	50	6	229	44
Ecuador	12	12	849	849
China	7	4	-	-
Suriname	-	-	3,087	1,389
Nicaragua	-	-	1,977	1,977
Cyprus	-	-	1,136	795
India	-	-	694	347
Total International	271	104	11,410	6,972
Total (2)	2,030	1,144	13,537	8,596

(1) The North Sea includes acreage in the UK and the Netherlands.

(2) Approximately 687,000 gross acres (407,000 net acres) will expire in 2010, 1.4 million gross acres (975,000 net acres) will expire in 2011, and 172,000 gross acres (121,000 net acres) will expire in 2012 if production is not established or we take no other action to extend the terms of the leases or concessions.

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

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

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, 2009							
United States							
Northern Region	2.5	1.0	3.5	516.9	1.0	517.9	521.4
Southern Region	1.6	0.6	2.2	15.4	1.0	16.4	18.6
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
Year Ended December 31, 2008							
United States							
Northern Region	1.0	-	1.0	837.2	42.0	879.2	880.2
Southern Region	14.6	2.0	16.6	30.9	2.0	32.9	49.5
Equatorial Guinea (1)	1.3	-	1.3	-	-	-	1.3
North Sea	-	0.4	0.4	0.6	0.3	0.9	1.3
Suriname	-	0.5	0.5	-	-	-	0.5
Total	16.9	2.9	19.8	868.7	44.3	913.0	932.8
Year Ended December 31, 2007							
United States							
Northern Region	13.9	1.9	15.8	738.0	24.5	762.5	778.3
Southern Region	0.3	2.6	2.9	19.6	3.1	22.7	25.6
Equatorial Guinea (1)	2.1	0.5	2.6	-	-	-	2.6
Cameroon (1)	0.5	-	0.5	-	-	-	0.5
Israel	-	-	-	0.4	-	0.4	0.4
North Sea	0.5	-	0.5	-	-	-	0.5
Argentina (2)	-	0.1	0.1	6.7	-	6.7	6.8
Total	17.3	5.1	22.4	764.7	27.6	792.3	814.7

(1) Includes successful exploratory wells drilled but not yet producing.
(2) We sold our assets in Argentina in February 2008.

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.

In addition to the wells drilled and completed in 2009 included in the table above, at December 31, 2009, we were in the process of drilling or completing 152 gross (113.2 net) wells in the Northern region of our US operations, two gross (0.7 net) onshore wells in the Southern region of our US operations, two gross (0.6 net) wells in the deepwater Gulf of Mexico, one gross (0.3 net) well in the North Sea, and one gross (0.6 net) well in China.

Marketing Activities We seek opportunities to enhance the value of our US natural gas production by marketing directly to end-users and aggregating natural gas to be sold to natural gas marketers and pipelines. We sell our natural gas production at both market-based and fixed prices. In 2009, approximately 28% of natural gas sales were made pursuant to long-term contracts under either fixed or market-based prices.

Crude oil, condensate and NGLs produced in the US and foreign locations are generally sold under short-term contracts at market-based prices adjusted for location and quality. In China, we sell crude oil into the local market under a long-term contract at market-based prices. In Israel, we sell natural gas under long-term contracts at negotiated prices. Crude oil and condensate are distributed through pipelines and by trucks or tankers to gatherers, transportation companies and refineries.

Delivery Commitments Some of our natural gas sales contracts specify the delivery of a fixed and determinable quantity of product. We have commitments to deliver approximately 220 Bcf of natural gas, net to our interest, to various customers in Israel through the year 2022. Approximately 90% of this amount will be delivered by 2015. We expect to fulfill the delivery commitments with proved developed and proved undeveloped reserves from the Mari-B and other nearby fields in Israel and we do not expect any shortfall. See International – Eastern Mediterranean (Israel and Cyprus).

Significant Purchaser Glencore Energy UK Ltd (Glencore) was the largest single non-affiliated purchaser of 2009 production and purchased our share of production from the Alba field in Equatorial Guinea under a short-term sales contract, subject to renewal. Sales to Glencore accounted for 25% of 2009 crude oil sales, or 16% of 2009 total oil and gas sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2009. 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 2009 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 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 – *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 6. Derivative Instruments and Hedging Activities.

Termination of Contracts See Item 1A. Risk Factors – *Our operations and investment in Ecuador may be adversely affected by the country's unsettled economic and political environment,* Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – Current Conditions in Ecuador, and Item 8. Financial Statements and Supplementary Data – 3. Impairments.

Regulations

Government Regulation Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated at the international, federal, state 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 burden on 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 are often difficult and costly to comply with, 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 burden on the crude oil and natural gas industry increases our costs of doing business and consequently affects our profitability. See Item 1A. Risk Factors – *We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.*

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) and the Minerals Management Service (MMS), which under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act have certain authority over our operations on federal lands, particularly in the Rocky Mountains and deepwater Gulf of Mexico;
- the US Environmental Protection Agency (EPA) and the Occupational Safety and Health Administration, which under laws such as the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act, the Occupational Safety and Health Act and the recent Final Mandatory Reporting of Greenhouse Gases Rule have certain authority over environmental, health and safety matters affecting our operations as discussed below;

- the Federal Energy Regulatory Commission, 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;
- the Department of Transportation, which has certain authority over the transportation of products, equipment and personnel necessary to our US onshore and deepwater Gulf of Mexico operations; and
- other federal agencies with certain authority over our business, such as the Internal Revenue Service and the SEC, as well as the NYSE upon which shares of our common stock are traded.

In January 2010, the BLM announced that it will be issuing a new draft oil and gas leasing policy that will require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, 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. As the policy has not yet been released, we are not able to determine the impact these potential leasing policy changes may have on our business.

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, which was adopted by the Colorado Oil and Gas Conservation Commission to address oil and gas well drilling, production, commingling and spacing in the Wattenberg field, and the same Commission's December 10, 2008 approval of a comprehensive update to statewide rules governing oil and gas operations in Colorado. These rules were reviewed by the Colorado legislature in its 2009 session and became effective in the second quarter of 2009, addressing areas such as public drinking water protection, monitoring and disclosure of chemicals used in drilling operations, erosion management and environment and wildlife protection. 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.

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.

Our international operations are subject to legal and regulatory oversight by energy-related ministries of our host countries, each having certain relevant energy or hydrocarbons laws. Examples of these ministries include the Ecuador Ministry of Nonrenewable Natural Resources, the Equatorial Guinea Ministry of Mines, Industry and Energy, the Israel Ministry of National Infrastructures, and the UK Department of Energy and Climate Change. An example of a law affecting our international operations is the UK Finance Act of 2006, which increased the income tax rate on our UK operations effective January 1, 2006.

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. 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 various governmental regulations and environmental risks that may cause us to incur substantial 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 in our efforts 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.

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 and numerous independent crude oil and natural gas companies, individuals and drilling partnership programs. 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, Corporate and Marketing. See Item 8. Financial Statements and Supplementary Data – Note 15. Segment Information.

Employees

Our total number of employees increased from 1,571 at December 31, 2008 to 1,630 at December 31, 2009. The 2009 year-end employee count includes 154 foreign nationals working as employees in Ecuador, Israel, the UK, Equatorial Guinea and Cameroon. We regularly use independent contractors and consultants to perform various field and other services.

Offices

Our principal corporate office, including our offices for US and international operations, is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. We maintain additional offices in Ardmore, Oklahoma and Denver, Colorado and in China, Cameroon, Ecuador, Equatorial Guinea, Israel 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 production sharing contracts or exploration licenses.

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.

Also posted on our website, and available in print upon request made by any stockholder to the Investor Relations Department, are charters for our Audit Committee; Compensation, Benefits and Stock Option Committee; Corporate Governance and Nominating Committee; and Environment, Health and Safety Committee. Copies of the Code of Business Conduct and Ethics, and the Code of Ethics for Chief Executive and Senior Financial Officers (the Codes) are posted on our website under the "Corporate Governance" section. Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

Item 1A. Risk Factors

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. There may be additional risks that are not presently material or known. You should carefully consider each of the following risks and all other information set forth in this Annual Report on Form 10-K.

If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected. In addition, the current global economic environment intensifies many of these risks.

Future economic conditions in the US and key international markets may materially adversely impact our operating results.

The US and other world economies are slowly recovering from a recession which began in 2008 and extended into 2009. Growth has resumed, but is modest. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than what was experienced in recent years. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate will result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results 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 settlement price for the prompt month oil contract in 2009 ranged from a high of $81.37 per barrel to a low of $33.98 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu. The markets and prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions, and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- 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 and biofuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- electricity generation;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- reducing the amount of crude oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income and cash flows; or
- limiting our access to sources of capital, such as equity and long-term debt.

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

- a reduction in the carrying value of our crude oil and natural gas properties; or
- a reduction in the carrying value of goodwill.

We recorded asset impairment charges during 2009. If commodity prices decline during 2010, there could be additional impairments of our oil and gas assets or other investments or an impairment of goodwill.

Market conditions may restrict our ability to obtain funds for future development and working capital needs, which may limit our financial flexibility.

During 2009, credit markets recovered but remain vulnerable to unpredictable shocks should weaker than expected economic growth persist. We have a significant development project inventory and an extensive exploration portfolio, which will require substantial future investment. We and our partners will need to seek financing in order to fund these or other activities. Our future access to capital, as well as that of our partners and contractors, could be limited if the debt or equity markets are constrained. This could significantly delay development of our property interests.

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 active drilling programs, such as the Wattenberg field, and our significant exploration and development programs in the deepwater Gulf of Mexico, West Africa and Israel. Significant capital investments on our inventory of major development projects will start next year and are estimated to be approximately $1 billion per year in 2010 and 2011. First production from these projects is not expected until 2011 and thereafter. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt issuances. Future cash flows 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 our access to debt or capital were limited, we would have a reduced ability to replace our reserves, resulting in a decrease in production over time. If our cash flows from operations are not sufficient to meet our obligations and fund our capital budget, 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, interests in some properties might be reduced or forfeited as a result.

Indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2009, we had long-term indebtedness of $2 billion (excluding unamortized discount), with $382 million drawn under our bank credit facility. Our indebtedness represented 25% of our total book capitalization at December 31, 2009.

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;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- additional financing in the future is likely to have higher costs due to the negative impact of the credit market crisis which restricted access to the bond markets;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and 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 such as our pending acquisition of additional US Rocky Mountain assets. A higher level of indebtedness increases the risk that our liquidity may become impaired and we default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness 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.

Hedging transactions may limit our potential gains.

In order to reduce 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 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 price fluctuation has been significant in 2009. Such volatility disrupts our ability to forecast and, as a result, we may become even more reliant on 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 cannot assure that our hedging transactions will reduce the risk or minimize the effect of volatility in crude oil or natural gas prices.

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 large joint venture development projects such as Aseng in Equatorial Guinea and Tamar in Israel. As operator of the joint ventures, we pay joint venture expenses and bill our nonoperating partners for their respective shares of joint venture costs. Some of our purchasers and joint venture partners are not as creditworthy as we are and may experience liquidity problems. Credit enhancements have been obtained from some parties in the way of parental guarantees or letters of credit, including our largest international 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.

We also monitor the creditworthiness of our counterparties on an ongoing basis. However, disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair their ability to perform under the terms of the hedging contract. We are unable to predict sudden changes in financial market conditions or a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a contract. To mitigate counterparty credit risk we conduct our hedging activities with a diverse group of major financial institutions. 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.

During periods of falling commodity prices, such as in late 2008 and first quarter 2009, our hedge receivable positions increase, which increases our counterparty exposure. If the creditworthiness of our counterparties, which are major financial institutions, deteriorates and results in their nonperformance, we could incur a significant loss.

We have over $1 billion in cash and cash equivalents invested in money market funds and short-term deposits with major financial institutions. During the first half of 2009, we shortened the duration of our bank deposits and held over 50% of our cash and cash equivalents in US Treasury securities. We maintained this investment posture well into the third quarter of 2009 before we started to reduce our US Treasury holdings in favor of reinvestment back into money market funds and time deposits with highly rated banks. 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. In the event of a bank failure, we could incur a significant loss.

We may not have enough insurance 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, 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. Our international operations are also subject to political risk.

In accordance 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. Although we believe the coverages and amounts of insurance carried are adequate, we may not have sufficient protection against some of the risks we face, because we chose not to insure certain risks, insurance is not available on commercially reasonable terms or actual losses exceed coverage limits. If an event occurs that is not covered by insurance or not fully protected by insured limits, it could have an adverse impact on our financial condition, results of operations and cash flows.

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.

We currently have an extensive inventory of major development projects, several of which will take years before first production, including the Aseng oil project, Tamar, Gunflint, and others. Some of these projects, such as oil and gas projects in West Africa, have a great deal of complexity. This level of development will require significant effort from our management and technical personnel as well as place additional burden on our financial resources and internal financial controls. We may not be able to attract and retain personnel with the skills necessary to bring complicated projects to successful conclusions.

In addition, we will have increased dependency on third-party technology and service providers and other vendors for these complex projects. Significant delays in delivery of essential items or performance of services, cost overruns, vendor insolvency, or other critical supply failure, could adversely affect development of our projects.

We may not be able to manage these and other risks effectively.

We may be unable to make attractive acquisitions, 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 Patina Merger in 2005, our purchase of U.S. Exploration in 2006 and the pending acquisition of additional US Rocky Mountain assets. 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 another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own, or could assume unidentified or unforeseeable liabilities, resulting in a loss of value.

We also engage in portfolio rationalization, such as the sale of our interest in Argentina in 2008, and the majority of our Gulf of Mexico shelf properties in 2006. These transactions can also result in changes in operations, systems, or management and other personnel.

Organizational modifications due to acquisitions, divestitures or portfolio rationalizations, 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 difficulties could be overcome, we cannot provide assurance that the anticipated benefits of any acquisition, divestiture or other strategic change would be realized.

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 adopted 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 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 new oil and gas company reserves reporting requirements;
- assumptions concerning future crude oil and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; 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 engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, 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.

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:

- pipeline ruptures and spills;
- fires;
- explosions, blowouts and cratering;
- formations with abnormal pressures;
- equipment malfunctions;
- hurricanes, such as Gustav and Ike in 2008, 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; 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.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use 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, and area well data and other data may be limited or less-developed in some of the international areas in which we explore. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry holes or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or other irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and other oil field services 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 or qualified personnel. During these periods, the costs of rigs, equipment and supplies are substantially greater and their availability may be limited, particularly in areas of high activity and demand in which we concentrate, such as the Rocky Mountains and deepwater Gulf of Mexico, and in some international locations that typically have more limited availability of equipment and personnel, such as Ecuador, Israel and West Africa. During periods of increasing levels of exploration and production in response to strong demand for crude oil and natural gas, the demand for oilfield services and the costs of these services increase. Additionally, these services may not be available on commercially reasonable terms.

In the current economy, even though commodity prices have fallen from the high levels experienced in 2008, the costs of drilling rigs, equipment and supplies, though somewhat reduced, have not decreased to the levels that existed before the run-up in commodity prices that occurred in the first half of 2008. If drilling costs decline significantly, our long-term drilling rig contracts may require us to pay rates higher than the current market. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Contractual Obligations* for additional information on drilling rig contracts. As a result, an increase in profits may be more dependant on cost reduction than in previous years.

Exploration and development in the deepwater Gulf of Mexico involves significant financial risks.

Much of the deepwater Gulf of Mexico area lacks the physical and oilfield service infrastructure necessary for production. As a result, development of a deepwater discovery, such as Gunflint, may be a lengthy process and require substantial capital investment. We participate in certain other projects, such as Isabela and Double Mountain, for which we are not the operator. If we are not the operator of a project, we may have limited ability to exercise influence over the project or its costs. This could prevent the realization of targeted return on capital or lead to unexpected future losses.

In addition, there is limited availability of suitable drilling rigs, drilling equipment, support vessels, production and transportation infrastructure, qualified operating personnel, and deepwater drilling rigs are typically subject to long-term contracts. This can lead to difficulty and delays in consistently obtaining drilling rigs and other equipment and services at acceptable rates, which, in turn, may lead to projects being delayed or increased costs. This also makes it difficult to estimate the timing of production.

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 a large number of independent, technology-driven companies as well as both major and other independent crude oil and natural gas companies 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. For example, in the deepwater Gulf of Mexico we compete with major integrated crude oil and natural gas companies and in international locations such as the North Sea we compete with major integrated crude oil and natural gas companies as well as state-controlled multinational companies.

In addition, the economic recession has increased competitive pressures. Crude oil and natural gas exploration and production companies, as well as service and drilling companies, are striving to improve efficiency and profitability, primarily through cost reduction. This highly competitive environment could have an adverse impact on our business.

The marketability of our Rocky Mountain and 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 Rocky Mountain area and the 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 that we do not own. The lack of availability of capacity on these 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 some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or 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 harm our business and, in turn, our financial condition, results of operations and cash flows.

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 44% of our 2009 consolidated sales volumes coming from international operations. These operations may be adversely affected by political and economic developments, including the following:

- war, terrorist acts, civil disturbances, or territorial disputes, such as may occur in regions that encompass our operations, including Ecuador, Israel and West Africa;
- 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 and renegotiation, modification or nullification of existing contracts, such as may occur pursuant to the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea;
- changes in taxation policies, such as the UK Finance Act of 2006, which increased the income tax rate on our UK operations effective January 1, 2006, and the China Petroleum Special Profits Tax enacted in 2006, which imposed an excise tax on crude oil produced in the country;
- laws and policies of the US and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- foreign exchange restrictions;
- international monetary fluctuations and changes in the relative value of the US dollar as compared with the currencies of other countries in which we conduct business, such as the UK; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

We may not have enough insurance to cover any loss of property resulting from these risks.

Our operations and investment in Ecuador may be adversely affected by the country's unsettled economic and political environment.

The economic and political environment in Ecuador has become increasingly unsettled. We are aware that the Government of Ecuador is taking steps to renegotiate contracts or, in some cases, remove international oil and gas companies from its borders. We continue to have significant delinquent accounts and unpaid invoices related to electricity sales from our Machala power plant, and we recently entered into independent power purchase agreements for such sales, the long-term effect of which on payment is unknown. On August 24, 2009, we became aware that our proposed plan of development for the Amistad field (offshore Ecuador), which had been submitted to Ecuador's National Bureau of Hydrocarbons, had been rejected. In addition, on December 31, 2009, Ecuador's state oil company (Petroecuador) requested that Ecuador's Minister of Nonrenewable Natural Resources commence termination of our production sharing contract. On February 11, 2010, the Minister notified us of Petroecuador's request by delivering to us a copy of a letter of non-compliance dated December 31, 2009. The Minister provided us with 60 business days to respond to the allegations contained in the letter. We are uncertain as to the potential outcome of this matter, resolution of which could ultimately lead to a further reduction in the value of our investments in Ecuador which, as of December 31, 2009, had a net book value of approximately $72 million. See Item 8. Financial Statements and Supplementary Data – Note 3. Asset Impairments.

We are subject to various governmental regulations and environmental risks that may cause us to incur substantial 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 significant 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 significant liabilities on our part to the government 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.

Increased regulation of business practices could result in increased operating costs.

The current trend is toward increased regulation of business practices and additional reporting requirements. For example the EPA has recently 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 emissions data under a new reporting system on January 1, 2010 with the first annual report due March 31, 2011. We will be subject to these new reporting requirements, which will result in additional effort on the part of our personnel. In addition, other pending legislation, such as the pending climate change legislation that includes establishing a "cap and trade" system for restricting greenhouse gas emissions in the US, or pending hydraulic fracturing legislation that would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act, if enacted, will require an unprecedented compliance effort on the part of companies in the oil and gas industry. We may be required to make significant expenditures to comply with additional reporting requirements.

The proposed US federal budget for fiscal year 2011 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 1, 2010, the Obama administration released its proposed federal budget for fiscal year 2011. The proposed budget would repeal many tax incentives and deductions that are currently used by US oil and gas companies and impose new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands.

If these proposals are enacted, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact they may have on our business.

The adoption of pending climate change legislation could result in increased 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 June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The Senate's version, The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been introduced, but has not passed. Although these bills include several differences that require reconciliation before becoming law, both bills contain the basic feature of establishing a "cap and trade" system for restricting greenhouse gas emissions in the US. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. In addition to the pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulation that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. Since approximately 60% of our 2009 crude oil production and 51% of our 2009 natural gas production derive from the US, any laws or regulations that may be adopted to restrict or reduce emissions of US greenhouse gases could require us to incur increased operating costs, and could have an adverse effect on demand for the crude oil and natural gas we produce.

Federal hydraulic fracturing legislation could increase our costs and restrict our access to oil and gas reserves.

Several proposals are before Congress that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs. Such legislation could have a significant impact on our development of the Wattenberg field, our largest onshore US field.

Although it is not possible at this time to predict the final outcome of the legislation regarding hydraulic fracturing, any new federal restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

Derivatives regulation could restrict our ability to execute commodity derivative instruments as a hedge against fluctuating commodity prices.

Various measures are being proposed by committees of Congress, the US Treasury Department, and other agencies to restrict the use of over-the-counter (OTC) derivative instruments. These proposals include, but are not limited to, requiring cash collateral on all OTC derivatives and requiring all OTC derivatives to be executed and settled through an exchange system.

Although we do not currently know the exact form any final legislation or rule-making activity will take, any restriction on the use of OTC instruments could have a significant impact on our business. Limits on the use of OTC instruments could significantly reduce our ability to execute strategic price hedges to reduce price uncertainty and to protect cash flows. In addition, cash collateral requirements could create significant liquidity issues and exchange system trades may restrict our ability to execute derivative instruments to fit our strategic needs.

Healthcare reform legislation could adversely impact us.

On November 7, 2009, the House of Representatives passed its healthcare reform bill, the Affordable Health Care for America Act, H.R. 3962. Among other initiatives, this bill authorizes the creation of a national public plan that would negotiate rates with providers and would be offered through a new national health insurance exchange market. On December 24, 2009, the Senate passed its own version of a healthcare reform bill, the Patient Protection and Affordable Care Act, H.R. 3590. The Senate bill contains no provision for a public plan but does authorize the creation of at least two multi-state plans.

At this time, it remains unclear how or when the differences between the two bills will be resolved, or if a final bill ultimately will be enacted. Various healthcare reform proposals have also emerged at the state level. We cannot predict what healthcare initiatives, if any, will be implemented at the federal or state level, or the effect any future legislation or regulation will have on us. However, an expansion in government's role in the US healthcare industry could have a significant impact on our employment benefits and related costs.

We face various risks associated with the trend toward increased activism against oil and gas development activities.

Opposition toward oil and gas drilling and development activity has been growing domestically as well as in countries belonging to the Organization for Economic Cooperation and Development (OECD), an international group of member countries sharing a commitment to democratic government and market economy. Companies in the petroleum industry, such as us, are often the target of activist efforts 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 and delay or cancel certain projects such as development of oil shale.

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;
- damaging publicity about us;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse affects 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.

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;

- effect of current volatility in the credit markets;
- 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; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “anticipate,” “estimate” 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.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

Purchaser Bankruptcy We had an exposure from crude oil sales for the months of June and July 2008 to SemCrude, L.P. (SemCrude), a subsidiary of SemGroup, L.P. (SemGroup). On July 22, 2008, SemGroup, including SemCrude, filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code under Case Number 08-11525 (BLS) in the United States Bankruptcy Court for the District of Delaware. During 2008, we determined that the carrying value of our receivable of $71 million should be reduced by $38 million. Based upon the confirmation of SemCrude's plan for reorganization on October 26, 2009 and further based upon a settlement reached with SemCrude on October 27, 2009, we further reduced the carrying value of our receivable by $12 million. We have received distributions of approximately $21 million from SemCrude and believe the disposition of this matter to be finally determined.

Legal Proceedings We are involved in various legal proceedings, including the foregoing matters 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 do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders in the fourth quarter of 2009.

Executive Officers

The following table sets forth certain information, as of February 18, 2010, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	59	Chairman of the Board, Chief Executive Officer and Director
David L. Stover (2)	52	President, Chief Operating Officer
Kenneth M. Fisher (3)	48	Senior Vice President, Chief Financial Officer
Ted D. Brown (4)	54	Senior Vice President, Northern Region
Rodney D. Cook (5)	52	Senior Vice President, International
Susan M. Cunningham (6)	54	Senior Vice President, Exploration
Arnold J. Johnson (7)	54	Senior Vice President, General Counsel and Secretary
Andrea Lee Robison (8)	51	Vice President, Human Resources

(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 a Senior Vice President and Chief Financial Officer of Noble Energy in November 2009. Prior to joining Noble Energy, Mr. Fisher served as Executive Vice President of Finance for Upstream Americas for Shell from July 2009 to November 2009. Prior to his most recent position with Shell, Mr. Fisher served as Director of Strategy & Business Development for Royal Dutch Shell plc in The Hague from August 2007 to July 2009. He served as Executive Vice President of Strategy & Portfolio for Shell's downstream business in London from January 2005 to August 2007 and was responsible for leading global strategy, portfolio, fuels development and biofuels activity along with central health, safety and environment functions. 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 (GE) from 1984 to 2002, including Vice President and Chief Financial Officer of the Aircraft Engines Services division and a Singapore-based position as 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 us upon our acquisition of Patina in May 2005. He served as Senior Vice President of Patina from July 2004 to May 2005. Prior thereto he served as Director, Piceance Basin Asset along with Engineering Manager for Williams and Barrett Resources since 1993 and, before that, in various positions with Union Pacific Resources and Amoco Production Company.

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

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

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

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

PART II

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

Common Stock Our common stock, $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
2008			
First Quarter	$ 81.35	$ 69.18	$ 0.12
Second Quarter	103.83	75.79	0.18
Third Quarter	102.79	51.18	0.18
Fourth Quarter	54.01	33.15	0.18
2009			
First Quarter	$ 58.24	$ 40.33	$ 0.18
Second Quarter	69.07	50.86	0.18
Third Quarter	70.35	51.49	0.18
Fourth Quarter	74.09	62.25	0.18

On January 26, 2010, the Board of Directors declared a quarterly cash dividend of $0.18 per common share, which will be paid February 22, 2010 to shareholders of record on February 8, 2010.

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 February 5, 2010, the number of holders of record of our common stock was 744.

Stock Repurchases The following table summarizes repurchases of our common stock occurring fourth quarter 2009.

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)
10/01/09 - 10/31/09	-	$ -	-	-
11/01/09 - 11/30/09	320	66.72	-	-
12/01/09 - 12/31/09	-	-	-	-
Total	320	$ 66.72	-	-

(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, 2009.

Plan Category	Number of Securities to be Issued Upon Exercies 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	6,820,291	$ 45.01	5,274,898
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	6,820,291	$ 45.01	5,274,898

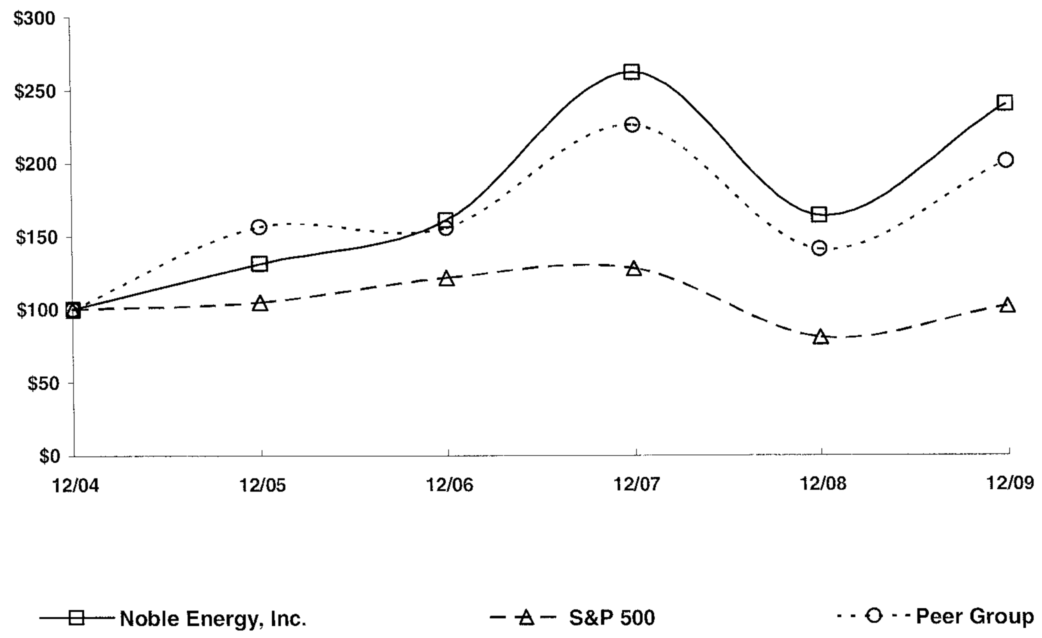
Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2004, to December 31, 2009. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index and our peer group of companies. At December 31, 2009, 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
Pioneer Natural Resources Company
Plains Exploration and Production Company
Range Resources Corp.
Southwestern Energy Company
XTO Energy Inc.

The comparison assumes $100 was invested on December 31, 2004, in our common stock, in the S&P 500 Index and in our peer group and assumes that all of the dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Noble Energy, Inc., The S&P 500 Index
And A Peer Group



*$100 invested on 12/31/04 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

Year Ended December 31,	2004	2005	2006	2007	2008	2009
Noble Energy, Inc.	$ 100.00	$ 131.24	$ 160.73	$ 262.26	$ 163.94	$ 240.11
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
Peer Group	100.00	156.47	155.59	226.10	141.02	200.93

Item 6. Selected Financial Data

	Year Ended December 31,				
	2009	2008	2007	2006 (1)	2005 (2)
(millions, except as noted)					
Revenues and Income (Loss)					
Total Revenues	$ 2,313	$ 3,901	$ 3,272	$ 2,940	$ 2,187
Net Income (Loss)	(131)	1,350	944	678	646
Per Share Data					
Earnings (Loss) Per Share					
Basic	$ (0.75)	$ 7.83	$ 5.52	$ 3.86	$ 4.20
Diluted	(0.75)	7.58	5.45	3.79	4.12
Cash Dividends Per Share	0.720	0.660	0.435	0.275	0.150
Year-End Stock Price Per Share	71.22	49.22	80.66	49.07	40.30
Weighted Average Shares Outstanding					
Basic	173	173	171	176	154
Diluted	173	176	173	179	157
Cash Flows					
Net Cash Provided by Operating Activities	$ 1,508	$ 2,285	$ 2,017	$ 1,730	$ 1,240
Additions to Property, Plant and Equipment	1,268	1,971	1,414	1,357	786
Acquisitions	-	292	-	412	1,111
Financial Position					
Cash and Cash Equivalents	1,014	1,140	660	153	110
Commodity Derivative Instruments - Current	13	437	15	35	29
Property, Plant, and Equipment, Net	8,916	9,004	7,945	7,171	6,199
Goodwill	758	759	761	781	863
Total Assets	11,807	12,384	10,831	9,589	8,878
Long-term Obligations					
Long-Term Debt	2,037	2,241	1,851	1,801	2,031
Deferred Income Taxes	2,076	2,174	1,984	1,758	1,201
Commodity Derivative Instruments	17	2	83	329	758
Asset Retirement Obligations	181	184	131	128	279
Other	349	300	337	275	280
Shareholders' Equity	6,157	6,309	4,809	4,114	3,090
Operations Information					
Consolidated Crude Oil Sales (MBpd)	62	69	77	75	57
Average Realized Price ($/Bbl) (3)	$ 55.76	$ 82.60	$ 60.61	$ 54.47	$ 45.35
Consolidated Natural Gas Sales (MMcfpd)	781	767	687	623	508
Average Realized Price ($/Mcf) (3)	$ 2.54	$ 5.04	$ 5.26	$ 5.55	$ 5.78
Consolidated NGL Sales (MBpd) (4)	10	9	-	-	-
Average Realized Price ($/Bbl)	$ 27.96	$ 50.15	$ -	$ -	$ -
Proved Reserves					
Crude Oil, Condensate and NGL Reserves (MMBbls)	336	311	329	296	291
Natural Gas Reserves (Bcf)	2,904	3,315	3,307	3,231	3,091
Total Reserves (MMBoe)	820	864	880	835	806
Number of Employees	1,630	1,571	1,398	1,243	1,171

(1) Includes effect of acquisition of U.S. Exploration and sale of Gulf of Mexico shelf properties.

(2) Includes effect of Patina Merger.

(3) Prices include effects of oil and gas hedging activities. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

(4) 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

We are an independent energy company engaged in worldwide crude oil, natural gas and NGL exploration and production. We operate primarily in the Rocky Mountains, Mid-continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel and West Africa.

The accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

EXECUTIVE OVERVIEW

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

Strategy We endeavor to continue our strong historic growth trend (7.9% average annual production growth rate from 2000 to 2009) to deliver superior value to our shareholders. We primarily focus on organic growth from exploration and development drilling, and we augment that with a strong, periodic new business development (mergers and acquisition) capability. We concentrate on basins or plays where we have strategic competitive advantage and which we believe offer superior returns. Core operating areas are the onshore US and deepwater Gulf of Mexico and the offshore Eastern Mediterranean and West Africa. We actively manage our portfolio with periodic divestments to "high grade" the portfolio. As a result of our continued exploration success, we are focused on the development of a significant portfolio of major projects in a number of key operating areas including, among others, Galapagos and Gunflint in the deepwater Gulf of Mexico, Tamar in Israel and Aseng and Belinda in 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 a balanced geographic and political risk profile. We also maintain a diversity of production mix between oil, US natural gas production and international gas.

Financial and Operating Results 2009 was a challenging year in the energy industry due to the prolonged recession, constraint in the credit markets, and commodity price volatility. These conditions resulted in our reduced net income and cash flows from operations. We reduced our capital spending program from our 2008 level as an outcome of the financial crisis. However, we were able to move forward on several major development projects as well as pursue additional exploration opportunities which resulted in important new discoveries, and we maintained our strong balance sheet and ample liquidity levels.

Our 2009 financial results included the following:

- net loss of $131 million as compared with net income of $1.4 billion for 2008;
- asset impairment charges of $604 million as compared with $294 million for 2008;
- $110 million loss on commodity derivative instruments (including unrealized mark-to-market loss of $606 million) as compared with a $440 million gain on commodity derivative instruments (including unrealized mark-to-market gain of $522 million) for 2008;
- diluted loss per share of $0.75, as compared with diluted earnings per share of $7.58 for 2008;
- cash flows provided by operating activities of $1.5 billion, as compared with $2.3 billion in 2008;
- capital spending of $1.3 billion as compared with $2 billion in 2008;
- issuance of $1 billion in 10-year unsecured notes;
- reduction of $225 million principal amount of debt;
- repatriation of $180 million of earnings from foreign subsidiaries;
- revenues of $86 million related to deepwater Gulf of Mexico royalties refund and $11 million of associated interest income;
- year-end cash balance of $1 billion, as compared with $1.1 billion at the end of 2008;
- total liquidity of $2.7 billion at December 31, 2009, consisting of year-end cash balance plus funds available under credit facility; and
- year-end ratio of debt-to-book capital of 25% as compared with 26% at December 31, 2008.

Significant operational highlights included the following:

Offshore United States

- discovery at Santa Cruz and sanction of the Galapagos oil development;
- successful new completion at the Swordfish field in the deepwater Gulf of Mexico;
- spud Deep Blue and Double Mountain exploration test wells in the deepwater Gulf of Mexico;
- Ticonderoga, in the deepwater Gulf of Mexico, returned to full production of approximately 5,000 Boepd, net in August 2009 after being offline due to Hurricane Ike in 2008; and
- award of 22 lease blocks from the Central Gulf of Mexico Lease Sale 208.

Onshore United States

- announced DJ Basin asset acquisition which will expand our largest onshore US property at Wattenberg;
- record Wattenberg field production of 269 MMcfepd, including liquid production of over 20 MBpd; and
- completion of our first horizontal East Texas Haynesville shale well with an initial thirty-day average production rate of over 11 MMcfpd, gross.

International

- sanctioned Aseng field oil development in Block I offshore Equatorial Guinea;
- successful exploration well and appraisal offshore Israel at Tamar, our largest discovery to date;
- executed two letters of intent to sell natural gas from the Tamar field offshore Israel with expected gross revenues of over $10 billion;
- additional natural gas discovery offshore Israel at Dalit;
- first oil discovery on Block O offshore Equatorial Guinea at the Carmen prospect;
- realized record natural gas prices in Israel; and
- completed field optimization efforts at the Dumbarton field and brought on line the first well at Lochranza in the North Sea.

In addition, we ended the year with total proved reserves of 820 MMBoe as compared with 864 MMBoe at the end of 2008. See Proved Reserves discussion below.

Impact of and Our Responses to the Recession and Current Credit and Commodity Markets Our business in 2009 was negatively impacted by the recession that began in 2008 and continues to impact the US and other world economies, as well as by the constraint in the credit markets and volatile commodity prices. During late 2008 and 2009, we took initiatives to strengthen our liquidity in response to the ongoing uncertainty. As a result of our actions, described below, we believe we are in a strong financial position with approximately $2.7 billion of liquidity, consisting of our cash plus funds available under our credit facility, sufficient to position us to initiate execution of our long-term business strategy including development of our major projects and increased exploration activity.

Debt In February 2009 we issued $1 billion of 8¼% senior notes due 2019 and used substantially all of the net proceeds to repay outstanding indebtedness under our credit facility.

At December 31, 2009, $1.7 billion was available for borrowing under our credit facility. The credit facility is committed in the amount of $2.1 billion until December 2011, at which time it reduces to $1.8 billion. If not extended, the credit facility matures in December 2012. Should current credit market conditions continue, future extensions of our credit facility may contain terms that are less favorable than those of the current credit facility. See Liquidity and Capital Resources below.

Cash We have over $1 billion in cash and cash equivalents invested in money market funds and short-term deposits with major financial institutions. During the first half of 2009, in response to the credit market crisis, we shortened the duration of our bank deposits and held over 50% of our cash and cash equivalents in US Treasury securities. We maintained this investment posture well into the third quarter of 2009 before we started to reduce our US Treasury holdings in favor of reinvestment back into money market funds and time deposits with highly rated banks. During first quarter 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes.

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. In the event of a bank failure, we could incur a significant loss.

Counterparty Credit Risk Counterparty risk related to our commodity derivative contracts and trade credit also increased. All of our commodity derivative instruments are with major financial institutions. Although our open commodity derivative instruments were in a net payable position at December 31, 2009, if one of these financial counterparties does not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss.

Commodity Prices Commodity prices continue to be volatile. Prices declined significantly during the last half of 2008 and into 2009. During 2009, the commodities market strengthened, but our average realized prices for 2009 were significantly lower than average realized 2008 prices. Lower commodity prices reduced our cash flows from operations as compared to prior years. To mitigate the impact of lower commodity prices on our cash flows, we entered into crude oil and natural gas commodity contracts for 2009, 2010 and 2011. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities. If we experience a "double-dip" recession, a short-lived recovery followed by another recession, commodity prices could decline again, which would further reduce our cash flows from operations. This may cause us to alter our business plans including further reduction or delay in our exploration and development program spending and/or implement other cost reduction and capital preservation initiatives. See 2010 Budget below.

Property Impairments The significant decreases in crude oil and natural gas prices resulted in a reduction of the carrying values of certain of our oil and gas properties. The commodity price decreases that began during the second half of 2008 required us to record asset impairment charges during fourth quarter 2008. Further declines in natural gas prices during first quarter 2009 led us to review those properties that, at year-end 2008, were susceptible to impairment should commodity prices decline appreciably. As a result of this review, we determined that additional properties were impaired as of March 31, 2009. We recorded additional impairment charges at December 31, 2009 due to price and/or performance issues. Future declines in commodity prices could result in additional impairment of our oil and gas properties, other long-lived assets or goodwill. We also recorded an impairment due to a dispute in Ecuador regarding our natural gas-to-power project. See Item 8. Financial Statements – Note 3. Asset Impairments.

Operating Costs We are closely monitoring costs and have implemented several cost savings initiatives, including continued reduction of well costs through drilling and completion efficiencies and comprehensive review of oil and gas operating costs. We are also continuing to see reductions in third-party drilling costs and operating supplies and services.

OPERATING OUTLOOK

2010 Production We expect that we will have a modest increase in crude oil, natural gas and NGL production in 2010 as compared with 2009 as a result of the acquisition of additional US Rocky Mountain assets scheduled to close first quarter 2010, and higher production in Israel and the North Sea. Our expected crude oil, natural gas and NGL production for 2010 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;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-continent areas of our US operations and in the North Sea;
- 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;
- successful closing on purchase of additional US Rocky Mountain assets;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas as occurred with Hurricanes Gustav and Ike in 2008;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- potential volume curtailments in Ecuador due to unsettled economic and political environment;
- impact of asset purchases;
- timing of significant project completion and initial production; and
- impact of sales of non-core operating assets.

2010 Budget Our total capital investment program for 2010 is estimated at $2.5 billion, with 40% going toward major project investments, 20% for exploration activities, and the remaining 40% for ongoing maintenance and near-term development opportunities. Approximately 55% of the total is to be spent in the US with the other 45% allocated to international activities.

Major project investments are expected to be about $1 billion, with the majority of capital directed toward the development of Galapagos in the deepwater Gulf of Mexico, Aseng offshore Equatorial Guinea, and Tamar offshore Israel. Approximately $500 million is slated for exploration activities, representing our largest ever annual exploration program. This program includes participation in seven high-impact offshore wells in the deepwater Gulf of Mexico, Equatorial Guinea and the Mediterranean Sea. The remainder of our budget is focused on liquid-rich and emerging opportunities onshore in the US, as well as near-term development projects in Israel, the North Sea and China.

Excluded from the capital budget discussed above is the $494 million we expect to pay for the DJ Basin asset acquisition scheduled to close in the first quarter 2010, as well as $235 million of non-cash capital expected to be accrued for the Aseng FPSO capital lease.

We expect that the 2010 budget will be funded primarily from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing. We will evaluate the level of capital spending throughout the year based on drilling results, commodity prices, cash flows from operations and property acquisitions and divestitures.

Exploration Program We have significant remaining exploration potential, primarily in the deepwater Gulf of Mexico and offshore Equatorial Guinea and Israel, and are planning to increase our level of exploratory activity in 2010 over that of 2009. We are currently engaged in drilling operations at two significant test wells in the deepwater Gulf of Mexico, one at the Deep Blue prospect and the second at the Double Mountain prospect, and plan to drill the Santiago exploratory well later in 2010. In addition, we are planning further exploratory drilling offshore Equatorial Guinea and another exploratory well offshore Israel, pending the outcome of a seismic program.

Exploratory activity, particularly offshore, is expensive and 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. Dry hole cost was particularly low in 2009 as compared with prior years, due to our unprecedented exploratory drilling success which resulted in new discoveries in Israel, Equatorial Guinea and the deepwater Gulf of Mexico. This level of exploratory success will be difficult to maintain. We are planning an active exploratory drilling program in 2010. As a result, dry hole cost could be significant.

Pending Asset Acquisition On December 31, 2009, we entered into a definitive agreement to acquire substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for $494 million. We estimate total proved reserves to be 53 MMBoe, 45% of which are liquids and 80% within the liquid-rich Wattenberg field in the Northern region of our US operations. The acquisition will add approximately 10 MBoepd or 46 MMcf of natural gas and 2.5 MBbls of liquids to our daily production base. The acquisition is expected to close late in the first quarter 2010 and is subject to customary closing conditions. Funding is expected to be provided through our existing credit facility.

Major Development Project Inventory Our current inventory of major development projects includes the Aseng oil project and the Galapagos oil project, both of which have been sanctioned, as well as Tamar, Gunflint, the Belinda cycling project, Diega/Carmen and other potential West Africa gas projects. These projects will require significant capital investments. For example, total development costs for the Aseng oil project, excluding costs related to a leased FPSO, are estimated at $1.3 billion ($530 million for our share). Our share of the development costs for the Galapagos oil project is estimated at $360 million.

We expect to spend approximately $1 billion per year in 2010 and 2011 for major project development. 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 such as a public debt offering. We expect first production to occur in 2011 when Galapagos comes on line, followed by Aseng and Tamar in 2012. Once these three projects begin producing, we expect to begin generating sufficient amounts of cash flow to self-fund the remaining discovered major projects investments.

As operator on the Aseng and Tamar development projects, we pay joint venture expenses and bill our nonoperating partners for their respective shares of joint venture costs. This increases our counterparty credit risk substantially. See Impact of Recession and Current Credit and Commodity Markets – Counterparty Credit Risk, above, and 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* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments*.

Growing Israel Natural Gas Realizations During third quarter 2009, we signed a new natural gas sales contract with our primary customer, IEC, under the terms of which they will purchase the majority of our remaining undedicated Mari-B field gas at prices expected to be significantly higher than what we have been receiving under the original contract. The actual price received is tied to a blend of liquids prices and a producer price index. In addition, it was agreed that all sales from the Mari-B field going forward will be proportionately allocated between the two contracts regardless of the total volume sold. This is a major change from the past arrangement wherein only "excess" volumes above a threshold level received premium prices.

In addition, in fourth quarter 2009, we announced that we had signed an LOI to sell natural gas from the Tamar field, offshore Israel, to Dalia Power Energies (Dalia). Dalia, a privately-owned electricity company, has a license to build a natural gas-fired power plant in Israel with operations planned to commence in 2013. According to terms of the LOI, we and our partners will deliver natural gas volumes of approximately 200 Bcf to Dalia under a 17-year supply agreement. Total revenues for these volumes are estimated to be at least $1 billion. Sales volumes under the LOI may be increased to 700 Bcf depending upon the final size of the power plant and extent of operations. We also signed an LOI to sell natural gas from the Tamar field to IEC. IEC expects to purchase at least 95 Bcf of natural gas per year with the potential to procure significantly higher quantities for a period of 15 years beginning at the startup of Tamar.

Potential Asset Sale We maintain an ongoing portfolio optimization program which may result in the divestiture of non-core operating assets in order to maintain a balanced portfolio of high-quality, core properties. In 2009, we conducted a market test of our wholly-owned subsidiary Noble Energy (Europe) Limited, which holds our interests in the Netherlands and the UK, and received bids. However, we have not committed to a plan to sell these assets.

Current Conditions in Ecuador The economic and political environment in Ecuador has become increasingly unsettled. See Item 1A. Risk Factors – *Our operations and investment in Ecuador may be adversely affected by the country's unsettled economic and political environment* and Item 8. Financial Statements and Supplementary Data – Note 3. Asset Impairments.

Climate Change Climate change has become the subject of an important public policy debate. While climate change remains a complex issue, scientific research suggests that an increase in greenhouse gas emissions (GHGs) may pose a risk to society and the environment. 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, although Congress and several states are considering adopting climate change legislation. The current state 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.

Impact of International Accords The Kyoto Protocol to the United Nations Framework Convention on Climate Change went into effect in February 2005 and requires all industrialized nations that ratified the Protocol to reduce or limit greenhouse gas emissions to a specified level by 2012. The US has not ratified the protocol. The US, Israel, and the European Union have participated in international discussions to develop a treaty or other agreement to require reductions in greenhouse gas emissions after 2012 and have indicated that they wish to associate themselves with the Copenhagen Accord, which includes a non-binding commitment to reduce greenhouse gas emissions.

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 climate change. See Items 1 and 2. Business and Properties – Regulation and the following risk factors listed in Item 1A. Risk Factors –

- *We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs;*
- *Increased regulation of business practices could result in increased operating costs; and*
- *The adoption of pending climate change legislation could result in increased operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.*

In terms of opportunities, the regulation of GHGs and introduction of formal technology incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways.

First, more than 60% of our 2009 production was natural gas. Climate change legislation could reduce the demand for the crude oil and natural gas 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 climate change regulation. 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, should states adopt low-carbon fuel standards, 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 increase our costs, and damage resulting from extreme weather may not be fully insured. However, the extent to which climate change may lead to increased storm or weather hazards affecting our operations, particularly our offshore operations, is difficult to identify at this time. See Item 1A. Risk Factors – *We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.*

RESULTS OF OPERATIONS

Selected financial information is as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions, except per share)			
Total Revenues	$ 2,313	$ 3,901	$ 3,272
Total Operating Expenses	2,371	2,266	1,777
Operating Income (Loss)	(58)	1,635	1,495
Total Other (Income) Expense	206	(426)	127
Income (Loss) Before Income Taxes	(264)	2,061	1,368
Net Income (Loss)	(131)	1,350	944
Earnings (Loss) Per Share			
Basic	$ (0.75)	$ 7.83	$ 5.52
Diluted	(0.75)	7.58	5.45

Factors contributing to the decrease in net income in 2009 as compared with 2008 included the following:

- $1.6 billion decrease in total revenues due primarily to lower commodity prices;
- $110 million mark-to-market loss on derivative instruments;
- $604 million asset impairment charges; and
- $25 million increase in DD&A expense;

offset by:

- $86 million refund of deepwater Gulf of Mexico royalties plus interest of $11 million;
- $69 million decrease in total production costs; and
- $73 million decrease in exploration expense.

Factors contributing to the increase in net income in 2008 as compared with 2007 included the following:

- $629 million increase in total revenues due primarily to higher commodity prices; and
- $440 million mark-to-market gain on derivative instruments;

offset by:

- $294 million asset impairment charges;
- $106 million increase in total production costs;
- $55 million increase in DD&A expense; and
- $38 million write-down of receivable from Semcrude, L.P.

Discontinuance of Cash Flow Hedge Accounting Effective January 1, 2008, we discontinued cash flow hedge accounting on all existing commodity contracts (or "commodity derivative instruments"). We voluntarily made this change to simplify the accounting for our commodity hedge program as well as to add more transparency in related disclosures for the benefit of our investors. From January 1, 2008 forward, we recognize all gains and losses on such instruments in earnings in the period in which they occur. The discontinuance of cash flow hedge accounting for commodity derivative instruments has no impact on our net assets or cash flows and previously reported amounts have not been adjusted. However, the use of mark-to-market accounting adds volatility to our net income.

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. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

Oil, Gas and NGL Sales

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

	Crude Oil and Condensate	Natural Gas	NGLs [1]	Total
(millions)				
2007 Sales Revenues	$ 1,694	$ 1,272	$ -	$ 2,966
Changes due to				
Increase (Decrease) in Sales Volumes	(152)	165	175	188
Increase in Sales Prices Before Hedging	701	73	-	774
Change in Amounts Reclassified from AOCL	(142)	(135)	-	(277)
2008 Sales Revenues	2,101	1,375	175	3,651
Changes due to				
Increase (Decrease) in Sales Volumes	(232)	15	-	(217)
Decrease in Sales Prices Before Hedging	(915)	(655)	(77)	(1,647)
Change in Amounts Reclassified from AOCL	307	(34)	-	273
2009 Sales Revenues	$ 1,261	$ 701	$ 98	$ 2,060

(1) For 2007, US NGL sales volumes were included with natural gas volumes. Effective in 2008, we began reporting US NGLs separately, which lowered the comparative natural gas sales revenues from 2007 to 2008 and 2009.

Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBpd)	Natural Gas (MMcfpd)	NGLs (MBpd) [1]	Total (Boepd)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2009							
United States [2]	37	397	10	113	$ 55.19	$ 3.61	$ 27.96
Equatorial Guinea [3]	14	239	-	54	55.94	0.27	-
Israel	-	114	-	19	-	3.47	-
North Sea	7	5	-	8	59.51	5.75	-
Ecuador [4]	-	26	-	4	-	-	-
China	4	-	-	4	54.40	-	-
Total Consolidated Operations	62	781	10	202	55.76	2.54	27.96
Equity Investees [5]	2	-	6	8	59.51	-	36.03
Total	64	781	16	210	$ 55.87	$ 2.54	$ 31.20
Year Ended December 31, 2008							
United States [2]	40	395	9	116	$ 75.53	$ 8.12	$ 50.15
Equatorial Guinea [3]	15	206	-	49	88.95	0.27	-
Israel	-	139	-	23	-	3.10	-
North Sea	10	5	-	11	100.56	10.54	-
Ecuador [4]	-	22	-	4	-	-	-
China	4	-	-	4	82.66	-	-
Total Consolidated Operations	69	767	9	207	82.60	5.04	50.15
Equity Investees [5]	2	-	6	8	96.77	-	58.81
Total	71	767	15	215	$ 82.96	$ 5.04	$ 53.45
Year Ended December 31, 2007							
United States [2]	42	412	-	111	$ 53.22	$ 7.51	$ -
Equatorial Guinea [3]	15	132	-	37	71.27	0.29	-
Israel	-	111	-	18	-	2.79	-
North Sea	13	6	-	14	76.47	6.54	-
Ecuador [4]	-	26	-	4	-	-	-
China	4	-	-	4	58.79	-	-
Argentina	3	-	-	3	46.79	-	-
Total Consolidated Operations	77	687	-	191	60.61	5.26	-
Equity Investees [5]	2	-	6	8	74.87	-	48.87
Total	79	687	6	199	$ 60.94	$ 5.26	$ 48.87

(1) Effective in 2008, we began reporting US NGLs separately, which has lowered the comparative natural gas sales volumes from 2007 to 2008 and 2009. For 2007, US NGL sales volumes were included with natural gas volumes.

(2) Average realized crude oil and condensate prices reflect reductions of $2.13 per Bbl for 2009, $22.06 per Bbl for 2008, and $13.68 per Bbl for 2007 from hedging activities. Average realized natural gas prices reflect increases of $0.23 per Mcf for 2008 and $1.12 per Mcf for 2007 from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis. The price increases and reductions resulted from hedge gains and losses that had been previously deferred in accumulated other comprehensive income or loss (AOCL).

(3) Average realized crude oil and condensate prices reflect reductions of $5.57 per Bbl for 2009, $7.59 per Bbl for 2008 and $2.19 per Bbl for 2007 from hedging activities. The price reductions resulted from hedge losses that had been previously deferred in AOCL. Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(4) The natural gas-to-power project in Ecuador is 100% owned by our subsidiaries and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales are included in other revenues. See Electricity Sales and Expense below.

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

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)			
	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas
	2009		2008	
	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)
Year Ended December 31,				
United States	$ 12.26	$ 1.73	$ (3.85)	$ (0.07)
Equatorial Guinea	15.36	-	(2.97)	-
Total Consolidated Operations	10.86	0.91	(2.85)	(0.04)
Total	10.55	0.91	(2.77)	(0.04)

Crude Oil and Condensate Sales

2009 Compared with 2008 Crude oil sales decreased by a net $840 million, or 40%, in 2009 as compared with 2008. The decrease was primarily due to a 32% decline in consolidated average realized prices due to the decreased demand for oil. In the US, crude oil sales decreased by $359 million primarily due to lower average realized prices. US crude oil sales were also impacted by a 7% decline in sales volumes due to natural field decline in the deepwater Gulf of Mexico and Gulf Coast area and the shut-in of Ticonderoga in the deepwater Gulf of Mexico until August 2009 after being offline due to Hurricane Ike in 2008. This decline was offset by increased production from the Wattenberg field in the northern region of our US operations due to ongoing development activity. Internationally, West Africa crude oil sales decreased by $192 million primarily due to lower average realized prices, plus a 4% decrease in production due to timing of liftings. In the North Sea, crude oil sales decreased by $247 million. Although the average realized North Sea oil price was significantly less than in 2008, the decline in sales was primarily driven by a 38% decline in sales volumes due to natural field decline and downtime beginning in mid-August at the Dumbarton field due to FPSO repairs. Crude oil sales in China decreased $42 million due to lower average realized prices.

2008 Compared with 2007 Crude oil sales increased by a net $407 million, or 24%, in 2008 as compared with 2007. The increase was affected by both volume and price changes. In the US, crude oil sales increased by $286 million due to higher average realized prices. Sales volumes declined due to hurricane-related production shut-ins in the deepwater Gulf of Mexico from Hurricanes Gustav and Ike and declining production in the Gulf Coast onshore and Mid-continent areas of our US operations, offset by growth in the Rocky Mountain area of our US operations. Internationally, West Africa crude oil sales increased by $88 million due to higher average realized prices. North Sea crude oil sales increased by $39 million due to higher average realized prices, while sales volumes were affected by natural field decline. Other international crude oil sales decreased by $6 million primarily due to natural field decline in China.

Hedging Gains (Losses) Included in Revenues Crude oil sales include amounts reclassified from AOCL related to commodity derivative instruments which were accounted for as cash flow hedges through December 31, 2007. Amounts included decreases of $58 million in 2009, $365 million in 2008, and $223 million in 2007. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

Natural Gas Sales

2009 Compared with 2008 Natural gas sales decreased by a net $674 million, or 49%, in 2009 as compared with 2008. The decrease was primarily due to a 50% decline in consolidated average realized prices due to the decreased demand for natural gas. In the US, natural gas sales decreased by $653 million due to lower average realized prices. Overall, sales volumes remained about the same year to year. Increased production from the Wattenberg, Piceance and Western Oklahoma areas of our US operations were offset by natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-continent areas. Internationally, West Africa natural gas sales increased $3 million due to an increase in sales volumes. In Israel, natural gas sales decreased by $13 million. As a result of the new natural gas sales contract, discussed above, average realized prices in Israel increased. However, sales volumes declined 18% due to customer power plant downtime, warmer than normal winter weather conditions, and competing natural gas sales from Egypt. North Sea natural gas revenues decreased by $11 million primarily due to lower average realized prices.

2008 Compared with 2007 Natural gas sales increased by a net $103 million, or 8%, in 2008 as compared with 2007. The increase was affected by both volume and price changes. In the US, natural gas sales increased by $44 million primarily due to higher commodity prices despite lower sales volumes. Lower volumes were the result of several factors including hurricane-related production shut-ins in the deepwater Gulf of Mexico from Hurricanes Gustav and Ike, reduction for shrink gas associated with the natural gas liquids being reported separately, and declining production in the Gulf Coast onshore and Mid-continent areas of our US operations. The volume decline was offset by a successful drilling program in the Piceance basin along with less severe winter weather in the Rocky Mountain area of our US operations. Internationally, West Africa gas sales increased by $6 million from the previous year. Natural gas volumes were higher due to increased sales of natural gas from the Alba field in Equatorial Guinea;

however, the effect of higher production was somewhat offset by lower average realized gas prices. In Israel, natural gas sales increased by $44 million due to record sales volumes, which included the commencement of sales to the IEC power plant at Gezer, and higher average realized prices. In the North Sea, sales increased by $6 million primarily due to higher average realized prices.

Hedging Gains (Losses) Included in Revenues Natural gas revenues include amounts reclassified from AOCL related to commodity derivative instruments which were accounted for as cash flow hedges through December 31, 2007. Amounts included increases of $34 million in 2008 and $169 million in 2007. The impact was de minimis in 2009. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

NGL Sales

2009 Compared with 2008 NGL sales decreased by $77 million due to the decrease in average realized prices.

Effective in 2008, we began reporting US NGL sales separately. This has lowered the comparative natural gas sales volumes and revenues from 2007 to 2008. Most of our US NGL production is from the Wattenberg field and deepwater Gulf of Mexico.

Income from Equity Method Investees

We have a 45% interest in AMPCO, which owns and operates a methanol plant and related facilities. We also have a 28% interest in Alba Plant, which owns and operates an LPG processing plant. The plants and related facilities are located in Equatorial Guinea. We account for investments in entities that we do not control but over which we exert significant influence using the equity method of accounting.

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

	Year Ended December 31,		
	2009	2008	2007
Net Income (in millions)			
AMPCO and Affiliates	$ 18	$ 56	$ 83
Alba Plant	66	118	128
Dividends (in millions)			
AMPCO and Affiliates	29	65	97
Alba Plant	63	156	132
Sales Volumes			
Methanol (MMgal)	145	119	161
Condensate (MBpd)	2	2	2
LPG (MBpd)	6	6	6
Average Realized Prices			
Methanol (per gallon)	$ 0.60	$ 1.25	$ 1.09
Condensate (per Bbl)	59.51	96.77	74.87
LPG (per Bbl)	36.03	58.81	48.87

AMPCO and Affiliates Net income from AMPCO and affiliates decreased by $38 million, or 68%, in 2009 as compared with 2008 due to the significant decrease in the average realized price for methanol. The price decrease is a result of an oversupply of methanol and the impact of the economic slowdown. While average realized prices were down for the year, there was a significant increase in methanol prices during fourth quarter 2009. Methanol sales volumes increased as there was minimal down time for repairs as compared with 2008.

Net income from AMPCO and affiliates decreased by $27 million, or 33%, in 2008 as compared with 2007 due to decreases in methanol sales volumes that resulted from 95 days of down time for compressor and other equipment repair and maintenance. The decreases in methanol sales volumes were offset by higher average realized methanol prices.

Alba Plant Net income from Alba Plant decreased by $52 million, or 44%, in 2009 as compared with 2008 due to significant decreases in average realized prices for condensate and LPG. The price decrease is a result of decreases in crude oil prices and the impact of the economic slowdown. While average realized prices were down for the year, there was a significant increase in condensate and LPG prices during fourth quarter 2009.

Net income from Alba Plant decreased by $10 million, or 8%, in 2008 as compared with 2007 primarily due to the expiration of the Alba Plant tax holiday, offset by higher average realized condensate and LPG prices.

Other Revenues

Refund of Deepwater Gulf of Mexico Royalties We have recorded a refund of $86 million attributable to royalties that we previously paid on production of approximately 900 MBbls of crude oil and 3,000 MMcf of natural gas that was produced from January 1, 2003 through July 31, 2009 in the deepwater Gulf of Mexico. We have requested a refund from the MMS and anticipate receiving the monies in early 2010. Interest of $11 million related to the refund has been recorded in interest income. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

Other Other revenues include electricity sales and gathering, marketing and processing revenues. See Electricity Sales and Expense below. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

Costs and Expenses

Production Costs Production costs were as follows:

	Total per BOE	Total	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l (1)
(millions, except per unit)							
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 Costs (3)	$ 7.13	$ 525	$ 391	$ 45	$ 9	$ 47	$ 33
Total Production Costs per BOE		$ 7.13	$ 9.51	$ 2.30	$ 1.36	$17.50	$ 10.27
Year Ended December 31, 2008							
Lease Operating Expense (2)	$ 4.90	$ 371	$ 257	$ 39	$ 9	$ 53	$ 13
Production and Ad Valorem Taxes	2.19	166	135	-	-	-	31
Transportation Expense	0.75	57	49	-	-	7	1
Total Production Costs (3)	$ 7.84	$ 594	$ 441	$ 39	$ 9	$ 60	$ 45
Total Production Costs per BOE		$ 7.84	$ 10.43	$ 2.17	$ 1.07	$14.30	$ 15.94
Year Ended December 31, 2007							
Lease Operating Expense (2)	$ 4.62	$ 322	$ 213	$ 39	$ 8	$ 38	$ 24
Production and Ad Valorem Taxes	1.63	114	91	-	-	-	23
Transportation Expense	0.74	52	40	-	-	11	1
Total Production Costs (3)	$ 6.99	$ 488	$ 344	$ 39	$ 8	$ 49	$ 48
Total Production Costs per BOE		$ 6.99	$ 8.49	$ 2.89	$ 1.14	$ 9.81	$ 12.06

(1) Other international includes China and Argentina (through February 2008).
(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 remained flat overall in 2009 as compared with 2008. In the US, we initiated cost savings initiatives which included reduced repair programs and a reduction of other discretionary spending in our onshore US operations, including a reduced workover program in the Northern region. Lease operating expense increased in West Africa due to higher contractor costs. Lease operating expense decreased in the North Sea due to lower sales volumes. A higher volume of crude oil was inventoried, resulting in a deferral of production cost.

Lease operating expense increased by $49 million, or 15%, in 2008 as compared with 2007. The increase was the result of higher costs related to the continuing active drilling program in the Rocky Mountains and Mid-continent areas of our US operations and increased workover activity in the Piceance basin, Wattenberg field, and Mid-continent and Gulf Coast areas of our US operations. North Sea oil and gas operating costs increased due to expanded operations and higher costs at the Dumbarton development. Costs were also driven up by industry inflation resulting from the high level of exploration and production activities in 2008.

Production and ad valorem tax expense decreased by $72 million, or 43%, in 2009 as compared with 2008 due to reduced proceeds from sales attributable to lower commodity prices in the US and China and the cessation of production due to the sale of our interest in Argentina in 2008. Production and ad valorem tax expense increased by $52 million, or 46%, in 2008 as compared with 2007 due to higher commodity prices and also by an increase in volumes subject to such taxes, mainly in the Northern region of our US operations.

Transportation expense increased by $2 million, or 4%, in 2009 as compared with 2008 due to the start up of a new interstate crude oil transportation pipeline system used to market our Wattenberg production and offset by lower sales volumes in the North Sea. Transportation expense increased by $5 million, or 10%, in 2008 as compared with

2007 due to higher natural gas production in the Wattenberg field and increased production from the Swordfish development in the deepwater Gulf of Mexico.

The unit rate of total production costs per BOE decreased for 2009 as compared with 2008 primarily due to the decline in production and ad valorem taxes.

The unit rate of total production costs per BOE increased for 2008 as compared with 2007 due to rising third-party costs, higher production taxes and increased workover activity in the Piceance basin, Wattenberg field, and Mid-continent and Gulf Coast areas of our US operations.

Oil and Gas Exploration Expense Exploration expense was as follows:

	Total	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate [1]
(millions)						
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
Year Ended December 31, 2008						
Dry Hole Expense	$ 84	$ 42	$ 1	$ -	$ 8	$ 33
Seismic	57	50	-	3	4	-
Staff Expense	62	14	7	1	5	35
Other	14	13	-	-	1	-
Total Exploration Expense	$ 217	$ 119	$ 8	$ 4	$ 18	$ 68
Year Ended December 31, 2007						
Dry Hole Expense	$ 90	$ 50	$ 40	$ -	$ -	$ -
Seismic	65	55	1	1	8	-
Staff Expense	46	12	2	1	9	22
Other	18	17	-	-	-	1
Total Exploration Expense	$ 219	$ 134	$ 43	$ 2	$ 17	$ 23

(1) Other international includes Ecuador, China, Argentina (through February 2008), Suriname, Cyprus, and other international new ventures.

Exploration expense decreased by $73 million, or 34%, in 2009 as compared with 2008. The decrease was almost entirely related to the decrease in dry hole expense as a result of our recent exploration successes in the deepwater Gulf of Mexico, Israel and Equatorial Guinea. Dry hole expense in 2009 related primarily to an unsuccessful exploratory well drilled in the Northern region.

Exploration expense was flat in 2008 as compared with 2007. Dry hole expense in 2008 related to exploratory drilling in Suriname ($33 million); the deepwater Gulf of Mexico ($35 million); the North Sea ($8 million); and other onshore US areas ($7 million). Dry hole expense in 2007 related to a dry exploratory well in Equatorial Guinea and expense related to a secondary target of an exploratory well in Cameroon.

Exploration expense included stock-based compensation expense of $9 million in 2009, $1 million in 2008 and $2 million in 2007.

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

	Year Ended December 31,		
	2009	2008	2007
(millions, except unit rate)			
United States	$ 689	$ 646	$ 580
Equatorial Guinea	38	34	25
Israel	20	24	18
North Sea	34	55	81
Other International, Corporate, and Other	35	32	32
Total DD&A Expense [1]	$ 816	$ 791	$ 736
Unit Rate per BOE [2]	$ 11.08	$ 10.44	$ 10.55

(1) DD&A expense includes accretion of discount on asset retirement obligations of $14 million in 2009, $10 million in 2008, and $8 million in 2007.

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

Total DD&A expense increased in 2009 as compared with 2008 due to higher production in the Wattenberg, Piceance and western Oklahoma areas of our US operations and ongoing capital spending in our US operations, offset by lower sales volumes in the North Sea. In addition, fourth quarter 2009 DD&A was impacted by the change in the SEC's pricing rules from the use of year-end prices to 12-month average prices, which resulted in negative reserves revisions at December 31, 2009. This resulted in an increase in fourth quarter DD&A of approximately $16 million. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for effects of reserves revisions due to lower commodity prices at December 31, 2009.

Total DD&A expense increased in 2008 as compared with 2007 due to several factors including higher acquisition and/or development costs in the Wattenberg field and other US onshore areas, negative year-end reserves revisions in the US due to lower commodity prices, and higher natural gas sales volumes in Israel and West Africa, offset by declining production in the North Sea.

The increase in the unit rate for 2009 as compared with 2008 was due to the change in the mix of production, including a decrease in lower-cost volumes from Israel; ongoing capital spending in US onshore areas; and negative reserves revisions related to lower year-end 2009 commodity prices.

The decrease in the unit rate for 2008 as compared with 2007 was due to a change in the mix of production. Increased production of lower-cost natural gas volumes from the Alba field in Equatorial Guinea and Israel were partially offset by increased production from areas with higher acquisition and/or development costs, such as US onshore areas, and negative year-end reserves revisions in the US due to lower commodity prices.

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

	Year Ended December 31,		
	2009	2008	2007
G&A Expense (in millions)	$ 237	$ 236	$ 206
Unit Rate per BOE (1)	$ 3.22	$ 3.12	$ 2.96

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

G&A expense remained flat in 2009 as compared with 2008.

G&A expense increased by $30 million, or 15%, in 2008 as compared with 2007. Our increased activities required additional personnel, which resulted in higher payroll costs.

In addition, 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. See Item 8. Financial Statements and Supplementary Data – Note 13. Stock-based Compensation. G&A included stock-based compensation expense of $36 million in 2009, $38 million in 2008, and $25 million in 2007.

Asset Impairments Impairment expense was as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Asset Impairments	$ 604	$ 294	$ 4

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 – Note 3. Asset Impairments.

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

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Other Operating (Income) Expense, Net	$ 45	$ 134	$ 124

Other operating expense, net includes gain on asset sales; electricity generation expense; gathering, marketing and processing expense; (gain) loss on involuntary conversion of assets; settlement of legal proceedings; and other operating (income) expense, net. See Electricity Sales and Expense and (Gain) Loss on Involuntary Conversion below. See also Item 8. Financial Statements – Note 2. Summary of Significant Accounting Policies.

Net Gain on Asset Sales Net gain on asset sales includes a $24 million gain on the sale of our interest in Argentina in 2008. Recognition of the gain on the sale was deferred until second quarter 2009 when the Argentine government approved the sale.

Electricity Sales and Expense We have a 100% ownership interest in an integrated natural gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies fuel to the Machala power plant. Electricity sales are included in other revenues and electricity generation expense is included in other operating expense, net in the consolidated statements of operations.

Operating data is as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions, except as noted)			
Electricity Sales	$ 72	$ 56	$ 71
Electricity Generation Expense	18	57	57
Operating Income	54	(1)	14
Power Generation (GW)	902	749	912
Average Power Price ($/Kwh)	$ 0.080	$ 0.074	$ 0.078

The volume of natural gas produced and electric power generated in Ecuador are related to thermal electricity demand in Ecuador which typically declines at the onset of the rainy season. When Ecuador has sufficient rainfall to allow hydroelectric power producers to provide base load power, we provide electricity only to meet peak demand. As seasonal rains subside, we experience increasing demand for thermal electricity.

Electricity generation expense includes all operating and non-operating expenses associated with the plant, including DD&A expense and changes in the allowance for doubtful accounts. The allowance is necessary to cover potentially uncollectible balances related to the Ecuador power operations, as certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. In 2009, we reduced the allowance for doubtful accounts by $46 million and included the amount as a reduction in electricity generation expense as a result of amounts received related to a settlement. We charged additions to the allowance of $14 million in 2009, $11 million in 2008, and $14 million in 2007. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

At both December 31, 2009 and 2008, we assessed the recoverability of our Ecuador investment. As a result of these analyses, we determined that our investment was impaired and recorded pre-tax (non-cash) impairments of $100 million and $70 million, respectively. See Critical Accounting Policies and Estimates – Impairment of Proved Oil and Gas Properties and Other Investments and Item 8. Financial Statements – Note 3. Asset Impairments.

(Gain) Loss on Involuntary Conversion In 2009, we recorded a net gain of $9 million related to receipt of insurance claims for damage caused by Hurricanes Katrina and Rita. We recorded losses on involuntary conversion of $9 million in 2008 and $51 million in 2007 related to hurricane damage to our Gulf of Mexico Main Pass assets. The amounts are included in other operating expense, net in the consolidated statements of operations. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

Other Other operating expense, net includes reductions in the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser. Reductions totaled $12 million in 2009 and $38 million in 2008. See Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

(Gain) Loss on Commodity Derivative Instruments Gain (loss) on commodity derivative instruments was as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
(Gain) Loss on Commodity Derivative Instruments	$ 110	$ (440)	$ (2)

See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, below, and Item 8. Financial Statements and Supplementary Data – Note 5. Fair Value Measurements and Disclosures and Note 6. Derivative Instruments and Hedging Activities.

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

	Year Ended December 31,		
	2009	2008	2007
(millions, except per unit)			
Interest Expense	$ 129	$ 102	$ 130
Capitalized Interest	(45)	(33)	(17)
Interest Expense, Net	$ 84	$ 69	$ 113
Unit Rate, per BOE	$ 1.13	$ 0.91	$ 1.62

Interest expense increased in 2009 as compared with 2008. The increase primarily relates to our $1 billion 8¼% senior unsecured notes due March 1, 2019, which we issued on February 27, 2009. This increase was partially offset by a significant decrease in credit facility interest expense due to a decline in both the average outstanding balance and the average interest rate.

Interest expense decreased in 2008 as compared with 2007 due to declining interest rates applicable to our credit facility from 5.28% at December 31, 2007 to 0.80% at December 31, 2008, partially offset by a higher amount outstanding under our credit facility during 2008. See also Liquidity and Capital Resources – Financing Activities below.

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 West Africa, the deepwater Gulf of Mexico and Israel in 2009; West Africa, deepwater Gulf of Mexico and numerous projects in the Rocky Mountain area in 2008; and West Africa, the North Sea and deepwater Gulf of Mexico in 2007. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. At December 31, 2009, AOCL included a deferred loss of $2 million, net of tax, related to interest rate swaps. This amount is being reclassified into earnings, at the rate of $0.8 million per year, as an adjustment to interest expense over the term of our 5¼% senior notes due 2014. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense, net was as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Other (Income) Expense, Net	$ 12	$ (55)	$ 16

Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense, net.

Deferred Compensation (Income) Expense In connection with the Patina Merger in 2005, we acquired the assets and assumed the 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, 2009, approximately 45% 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 $23 million in 2009, deferred compensation income of $32 million in 2008, and deferred compensation expense of $33 million in 2007. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies and Note 12. Benefit Plans.

Interest Income Interest income for 2009 includes $11 million of interest related to the refund of deepwater Gulf of Mexico royalties. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

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

	Year Ended December 31,		
	2009	2008	2007
Income Tax Provision (Benefit) (millions)	$ (133)	$ 711	$ 424
Effective Rate	50%	35%	31%

Our effective tax rate increased to 50% for 2009 as compared with 35% for 2008 and is the result of a tax benefit divided by a pre-tax loss. In the case of a loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate. 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.

Our effective tax rate increased in 2008 compared to 2007 primarily due to the fact that pre-tax earnings increased by a proportionately greater amount than our excludible permanent differences. In addition, there was a rate increase due to (1) a partial shift of taxable income from lower rate jurisdictions such as Equatorial Guinea and Israel to higher rate jurisdictions, (2) the recording of US deferred taxes on the anticipated repatriation of a portion of our foreign earnings, and (3) the recording of an impairment for a foreign asset on which the tax benefit was offset by a valuation allowance. See Item 8. Financial Statements and Supplementary Data – Note 9. Income Taxes.

PROVED RESERVES

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

	Year Ended December 31,		
	2009	2008	2007
(MMBOE)			
Proved Reserves Beginning of Year	864	880	835
Revisions of Previous Estimates	(64)	(44)	30
Extensions, Discoveries and Other Additions	95	98	90
Purchase of Minerals in Place	2	15	-
Sale of Minerals in Place	-	(7)	(2)
Production	(77)	(78)	(73)
Proved Reserves End of Year	820	864	880

Revisions Revisions represent changes in previous reserves estimates, either upward or downward, 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 at year-end 2009 included reclassifications of proved undeveloped reserves to probable reserves as a result of the SEC's new five year development rule and lower natural gas prices, partially offset by higher crude oil prices. Revisions at year-end 2008 were primarily due to lower year-end 2008 commodity prices. Revisions at year-end 2007 included positive revisions resulting from an increase in crude oil prices, additional production allowance related to LNG sales in Equatorial Guinea, and both positive and negative changes due to well performance.

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

In 2009, US additions were primarily driven by the execution of low-risk development projects onshore in the Wattenberg and Piceance areas, as well as from the sanctioning of the Galapagos development in the deepwater Gulf of Mexico. International additions related primarily to the initial recording of reserves at the Aseng oil project in West Africa. In 2008, additions were due to infill drilling activities in the Northern region of our US operations, other US development programs and drilling in China. In 2007, additions were due to infill drilling activities in the Northern region and drilling activities in the deepwater Gulf of Mexico and North Sea.

We expect that a significant portion of future reserve additions will come from our major development projects at Aseng, Tamar and Gunflint; from continued drilling in the Northern region of our US operations; 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 Acquisition, Capital and Other Exploration Expenditures, below.

Purchases We occasionally enhance our asset portfolio with strategic acquisitions of producing properties. In 2008 we acquired producing properties in western Oklahoma. See Operating Outlook – Pending Asset Acquisition and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions and Divestitures.

Sales We maintain an ongoing portfolio optimization program. In 2008, we sold our Argentina asset. See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions and Divestitures.

Production See Oil, Gas and NGL Sales above.

See Operating Outlook – Pending Asset Acquisition, above, for a discussion of the pending acquisition of additional US Rocky Mountain assets, which we expect to add approximately 53 MMBoe of proved reserves in 2010. See also Critical Accounting Policies and Estimates – Reserves, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our development and major projects pipeline, we employ a capital structure and financing strategy designed to provide adequate liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle capital intensive development projects while also maintaining the capability for 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. Occasional sales of non-strategic crude oil and natural gas properties as well as our periodic access to capital markets may also generate cash.

Information regarding cash and debt balances was as follows:

	December 31,		
	2009	2008	2007
(millions, except percentages)			
Cash and Cash Equivalents	$ 1,014	$ 1,140	$ 660
Amount Available to be Borrowed Under Credit Facility	1,718	494	920
Total Liquidity	$ 2,732	$ 1,634	$ 1,580
Total Debt (Excluding Unamortized Discount)	$ 2,045	$ 2,270	$ 1,880
Total Shareholders' Equity	6,157	6,309	4,809
Debt-to-Capital Ratio (1)	25%	26%	28%

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

The ongoing disruption in the credit markets resulted in constrained access to the debt markets in the second half of 2008 and into the first quarter of 2009. Notwithstanding these conditions, we successfully completed a debt offering in February 2009 and issued $1 billion of 8¼%, 10-year senior notes, utilizing the proceeds to pay down debt under our revolving credit facility. Since the second half of 2009, improvements in capital market conditions have increased our options for financing our capital requirements.

Disruption in the credit markets also had a significant adverse impact on a number of financial institutions. We continue to review the creditworthiness of the banks and financial institutions with which we maintain our investments as well as the securities underlying our investments. Thus far, our liquidity and financial position have not been materially impacted. However, a recurrence of the constrained credit market conditions we experienced in late 2008 and early 2009 could adversely affect our results of operations and cash flows. See Executive Overview – Impact of Recession and Current Credit and Commodity Markets.

Cash and Cash Equivalents We had $1 billion in cash and cash equivalents at December 31, 2009, compared with $1.1 billion at December 31, 2008. At December 31, 2009, our cash was primarily denominated in US dollars and was invested in money market funds and short-term deposits with major financial institutions. Substantially all of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. 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 Israel.

In fourth quarter 2008, we performed an analysis of projected short-term working capital needs as well as long-term capital requirements for our US and foreign operations. As a result, we repatriated $180 million of the accumulated earnings of foreign subsidiaries during first quarter 2009. We used the proceeds for debt repayment and general corporate purposes.

Commodity Derivative Instruments We use various derivative contracts 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 commodity price swaps, collars and basis swaps.

As of December 31, 2009, we had commodity derivative assets totaling $14 million and commodity derivative liabilities totaling $117 million (after consideration of netting agreements). Our hedging arrangements are currently with a diversified group of financial institutions, substantially all of which are lenders under our credit facility arrangement. See Item 1A. Risk Factors – *Hedging transactions may limit our potential gain* 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. Except for certain minor derivative contracts that are entered into from time to time in our marketing operations, none of our counterparty agreements contain margin requirements. See additional information included in Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Accounts Receivable We have accounts receivable from sales of our crude oil, natural gas and NGLs, as well as electricity. We also have accounts receivable related to our joint venture partners. 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 international 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. Other than reductions in the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser that declared bankruptcy in 2008 and certain entities purchasing electricity in Ecuador, we have experienced no significant collection issues with purchasers or joint venture partners. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 1,508	$ 2,285	$ 2,017
Investing Activities	(1,265)	(2,132)	(1,403)
Financing Activities	(369)	327	(107)
Increase (Decrease) in Cash and Cash Equivalents	$ (126)	$ 480	$ 507

Operating Activities Net cash provided by operating activities totaled $1.5 billion in 2009, a decrease of $777 million, or 34% as compared with 2008 due primarily to decreases in sales revenues resulting from significant declines in commodity prices.

Net cash provided by operating activities totaled $2.3 billion in 2008, an increase of $268 million, or 13%, as compared with 2007. The increase was primarily due to a significant increase in oil, gas and NGL sales resulting from higher average realized crude oil and natural gas prices during the first nine months of 2008. The revenue increase was slightly offset by higher production costs and G&A expense. Net cash provided by operating activities includes dividends received 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. Net cash used in investing activities totaled $1.3 billion in 2009, as compared with $2.1 billion in 2008. In 2009, due to the uncertain economic and commodity price environment, we designed a flexible capital spending program that was responsive to conditions that developed during 2009, and targeted an investment level of approximately $1.4 billion. Investing activities related to deepwater Gulf of Mexico lease acquisitions, exploratory activity in the deepwater Gulf of Mexico, Equatorial Guinea and Israel and development activity in the Northern region of our US operations, Equatorial Guinea and the North Sea. Net proceeds from property sales totaled $3 million.

Net cash used in investing activities totaled $2.1 billion in 2008, as compared with $1.4 billion in 2007. In 2008 we had an expanded capital budget, with increased development, exploratory, and acquisition activity in onshore US and deepwater Gulf of Mexico areas as well as increased exploratory activity in international locations including Equatorial Guinea and Israel. Our total additions to property, plant and equipment plus acquisitions ($2.3 billion) were minimally offset by proceeds from property sales ($131 million).

In comparison, in 2007, additions to property, plant and equipment totaled $1.4 billion, primarily due to development activity in the US and North Sea and exploratory and acquisition activities in the US and West Africa. Expenditures were minimally offset by proceeds from property sales of $9 million.

Financing Activities 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).

In 2008, net cash of $327 million was provided by financing activities. We borrowed a net $426 million under our credit facility in support of an expanded capital budget, which included significant domestic exploration, development and acquisition activities and new international ventures. Funds were also provided by the cash proceeds from, and tax benefits related to, the exercise of stock options ($51 million). Other financing activities included the payment of cash dividends on our common stock ($115 million), the repayment of installment and other notes ($32 million) and the repurchase of stock ($3 million).

In comparison, in 2007, we used cash of $107 million in financing activities. Funds were provided by net borrowings ($25 million) and cash proceeds from, and tax benefits related to, the exercise of stock options ($45 million). We were able to use available cash to finance the repurchase of two million shares of our common stock ($102 million) and pay cash dividends on our common stock ($75 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,		
	2009	2008	2007
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition [1]	$ 92	$ 302	$ 146
Proved Property Acquisition [2]	(5)	256	11
Exploration	242	448	372
Development	881	1,193	1,175
Corporate and Other	107	65	35
Total	$ 1,317	$ 2,264	$ 1,739
Non-cash Capital Lease Accrual [3]	$ 29	$ -	$ -

(1) 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. Unproved property acquisition cost for 2008 includes $179 million for deepwater Gulf of Mexico lease blocks, $38 million related to the Mid-continent acquisition, $79 million related to additional onshore US lease acquisitions and $6 million related to international lease acquisitions.

(2) Proved property acquisition cost for 2008 includes $254 million related to the Mid-continent acquisition.

(3) Relates to estimated construction progress to date on an FSPO to be used in the development of the Aseng field in Equatorial Guinea.

Total expenditures in 2009 decreased by $947 million, or 42%, as compared with 2008, as we reduced our capital spending program in response to economic conditions.

Total expenditures in 2008 increased by $525 million, or 30%, as compared with 2007. The increase was due to increased development, exploratory and acquisition activity in onshore US and deepwater Gulf of Mexico areas as well as increased exploratory activity in international locations including Equatorial Guinea and Israel.

Asset Sales In February 2008, effective July 1, 2007, we sold our interest in Argentina for a sales price of $117.5 million.

Insurance Coverage

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of oil and gas, including hurricanes, blowouts, 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, employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We 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. Effective January 1, 2010, windstorm insurance coverage is provided subject to a $10 million per-occurrence deductible, a $150 million per-occurrence loss limit per member, an annual maximum of $300 million per member, and a $750 million industry aggregate per-event loss limit. Annual industry windstorm losses exceeding $300 million will be mutualized among windstorm members in two pools, one for offshore losses and one for onshore losses, with future premiums based upon a pool's loss experience and a member's weighted percent of the pool's asset base. As a result of our recent asset retirement efforts at Main Pass, our risk of windstorm damage has been reduced. We have not yet determined whether we will seek additional third-party insurance to replace the reduction in OIL coverage. See *Contractual Obligations* below for a discussion of our theoretical withdrawal premium liability.

For certain international locations (including Israel, Equatorial Guinea and Ecuador) 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.

Financing Activities

Long-Term Debt Our long-term debt totaled $2 billion (excluding unamortized discount) at December 31, 2009, with maturities ranging from 2012 to 2097. Our principal source of liquidity is an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are 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 credit facility. At December 31, 2009, $382 million in borrowings were outstanding under the credit facility, leaving $1.7 billion available for use. The weighted average interest rate applicable to borrowings under the credit facility at December 31, 2009 was 0.54%. We expect to use the credit facility to fund our planned $494 million acquisition of US Rocky Mountain assets in the first quarter 2010.

The credit facility contains customary representations and warranties and affirmative and negative covenants. The credit facility requires 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 could result in a default under the credit facility, which would permit the participating banks to restrict our ability to access the credit facility and require the immediate repayment of any outstanding advances under the credit facility. As of December 31, 2009, we were in compliance with our debt covenants.

The credit facility is with certain commercial lending institutions and its funds are available for general corporate purposes. Our bank group is comprised of 23 commercial lending institutions, each holding between 1.0% and 11.4% of the total facility. Due to recent consolidation in the banking sector resulting from heightened stress in the credit markets, the number of lenders and their effective commitment levels within our credit facility may be reallocated over time.

On February 27, 2009, we closed an offering of $1 billion senior unsecured notes receiving net proceeds of $989 million, after deducting the discount and underwriting fees, and 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%.

Including our new 8¼% notes, we had a total of $1.6 billion of fixed-rate debt outstanding at December 31, 2009 with a weighted average interest rate of 7.73%. Maturities range from 2014 to 2097.

Credit Rating Our senior unsecured debt is rated investment grade by both of the industry's recognized rating agencies. We are currently rated Baa2/Stable Outlook from Moody's and BBB/Stable Outlook from Standard & Poor's. Our latest rating action was an upgrade by Standard & Poor's in February 2009. The ratings reflect the agencies' view of our positive financial metrics due to our strong liquidity and conservative financial profile. Factors that could negatively pressure ratings could be driven by an overall negative industry outlook precipitated by a decline in oil and natural gas prices to levels that are likely to result in weak cash margins and fundamental credit deterioration or factors specific to us, such as deterioration in operating performance resulting in reduced cost competitiveness, lower capital productivity or events leading to a higher debt leverage profile in the capital structure. Adverse rating actions by the credit agencies would not trigger a covenant default in our credit facility or in any of our publicly held debt securities.

Short-Term Borrowings In May 2009, we made the final $25 million installment payment to the seller of properties we purchased in 2007. Interest on the unpaid amount was due quarterly and accrued at a LIBOR rate plus .30%. The interest rate was 1.51% at the date of payment.

Our committed credit facility has been supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no amounts outstanding under uncommitted credit lines at December 31, 2009 or 2008. Depending upon future credit market conditions, these sources may or may not be available. However, we are not dependent on them to fund our day-to-day operations.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital was 25% at December 31, 2009 and 26% at December 31, 2008. Significant changes in our financial position causing a change in the ratio of debt-to-book capital included the following:

- $225 million decrease in total principal amount of debt from the balance at December 31, 2008;

offset by:

- $131 million decrease in shareholders' equity from current year net loss; and
- $126 million decrease in shareholders' equity from dividends paid.

Interest Rate Locks We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. As of December 31, 2007, we had entered into two interest rate locks, each in the notional amount of $500 million. The locks were based on five and ten year US Treasury rates of 3.55% and 4.15%, respectively, and were scheduled to expire in September 2008. We settled the locks in July 2008 at a total cost of $0.2 million.

In January 2010, in anticipation of a long-term debt issuance, 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 is in the notional amount of $500 million and is based on a 30-year LIBOR swap rate.

Cash Interest Payments We made cash interest payments of $97 million in 2009, $109 million in 2008, and $122 million in 2007.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $17 million in 2009, $27 million in 2008, and $25 million in 2007. Proceeds received from the exercise of stock options fluctuate primarily based on the number of options exercised which is influenced by the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued.

Dividends We paid cash dividends totaling 72 cents per common share in 2009, 66 cents per common share in 2008, and 43.5 cents per common share in 2007. On January 26, 2010, the Board of Directors declared a quarterly cash dividend of 18 cents per common share, which will be paid February 22, 2010 to shareholders of record on February 8, 2010. The amount of future dividends will be determined on a quarterly basis at the discretion of the 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 21,000 shares with a total value of $1 million in 2009 and approximately 33,000 shares with a total value of $3 million in 2008. In 2007, we completed a common stock repurchase program authorized by our Board of Directors in 2006 and repurchased two million shares of our common stock at an aggregate cost of $102 million.

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, 2009, the material off-balance sheet arrangements and transactions that we have entered into included drilling service contracts, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry. Other than the off-balance sheet arrangements listed above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See *Contractual Obligations* below for more information regarding off-balance sheet arrangements.

Contractual Obligations

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

(millions)	Total	2010	2011 and 2012	2013 and 2014	2015 and beyond
Long-Term Debt (Excluding Interest) (1)	$ 2,016	$ -	$ 382	$ 200	$ 1,434
Obligation Under FPSO Lease (2)	468	-	35	138	295
Drilling and Equipment Obligations (3)					
United States	461	259	202	-	-
International	269	147	122	-	-
Purchase Obligations (4)	304	265	39	-	-
Throughput Agreement (5)	81	19	38	24	-
Transportation and Gathering (6)	40	11	17	9	3
Operating Lease Obligations (7)	83	12	19	21	31
Other Long-Term Liabilities (8)					
Asset Retirement Obligations (9)	232	51	31	7	143
Commodity Derivative Instruments (10)	117	100	17	-	-
Total Contractual Obligations	$ 4,071	$ 864	$ 902	$ 399	$ 1,906

(1) Long-term debt excludes obligation under FPSO lease. Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2009, our cash payments for interest would be $128 million in 2010, $128 million in 2011, $128 million in 2012, $126 million in 2013, $121 million in 2014 and $1.2 billion for the remaining years for a total of $1.8 billion. See Item 8. Financial Statements and Supplementary Data – Note 8. Debt.

(2) The FPSO is currently under construction. Annual lease payments, net to our interest, exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. These payments are also subject to change based on change orders implemented during the construction period, final accounting treatment, and other factors. See Item 8. Financial Statements and Supplementary Data – Note 8. Debt.

(3) Drilling and equipment obligations represent contractual agreements with third-party service providers to procure drilling rigs and other related equipment for developmental and exploratory drilling activities. See Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

(4) 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 17. Commitments and Contingencies.

(5) We have a five-year throughput agreement on a new interstate crude oil transportation pipeline system running from Weld County, Colorado to Cushing, Oklahoma, which became operational in 2009. See Item 8. Financial Statements and Supplementary Data – Note 17. 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 17. Commitments and Contingencies.

(7) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. See Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $213 million and accrued benefit costs of $76 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 12. Benefit Plans.

(9) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data – Note 10. Asset Retirement Obligations.

(10) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2009. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2009. See Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

As of December 31, 2009, we accrued approximately $28 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 in support of certain performance obligations of our subsidiaries. Outstanding letters of credit totaled approximately $4 million at December 31, 2009.

Other

Contributions to Pension and Other Postretirement Benefit Plans We made contributions to the pension and other postretirement benefit plans totaling $21 million in 2009, $38 million in 2008, and $12 million in 2007. The actual return on plan assets was a gain of $33 million in 2009, and a loss of $43 million in 2008. The investment return has tended to follow market performance. In August 2006, the Pension Protection Act of 2006 (the Act) was signed into law. Certain provisions of this Act changed the calculation related to the maximum contribution amount deductible for income tax purposes and require 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. In addition, due to the level of previous funding, we do not expect that there are any contributions that will be required in 2010. However, we made a contribution of $2 million to the pension plan in January 2010 and may make additional contributions to the plan during 2010. We expect to make contributions pertaining to the restoration and medical and life plans of approximately $3 million during 2010, 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 $227 million in 2009, $263 million in 2008, and $149 million in 2007.

Contingencies Payments to settle legal proceedings totaled approximately $19 million in 2009, $2 million in 2008, and $56 million in 2007. 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 generally accepted accounting principles 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 engineers in accordance with guidelines established by the SEC, including the recent rule revisions designed to modernize the oil and gas company reserves reporting requirements and which we adopted 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 dependant on the oil and gas prices used in the reserves estimate. We based our December 31, 2009 reserves estimates on a 12-month average commodity price, 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, to drill and equip exploratory wells that find commercial quantities of proved reserves, and to 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 engineers. Costs to drill and equip exploratory wells that find proved reserves and to 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 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 commercial quantities of crude oil or natural gas have been discovered. 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 access to such 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. At December 31, 2009, the balance of property, plant and equipment included $432 million of suspended exploratory well costs, $274 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 when events or circumstances indicate that the recorded carrying value 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. Downward 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 2009, we assessed certain proved properties for possible impairment due to lower commodity prices and/or performance issues. Certain assets were determined to be impaired. The impaired assets 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 also determined that our investment in Ecuador was impaired.

We recorded total pre-tax (non-cash) asset impairment charges of $604 million in 2009, $219 million in 2008 and $4 million in 2007. See Item 8. Financial Statements and Supplementary Data – Note 3. Asset Impairments.

Impairment of Unproved Oil and Gas Properties We also perform periodic 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 exploratory 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 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 natural gas and crude oil reserves, including 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.

Downward 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 natural gas and crude oil 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 at December 31, 2009 and determined there was no impairment.

We recorded impairments of significant unproved oil and gas properties of $75 million in 2008 and $3 million in 2007. See Item 8. Financial Statements and Supplementary Data – Note 3. Asset Impairments.

Purchase Price Allocations As a result of the Patina Merger in 2005 and the U.S. Exploration acquisition in 2006, we acquired assets and assumed liabilities in transactions accounted for as purchases. 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 purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves. We estimated future prices to apply to the estimated reserves quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were 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 was 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 were reduced by additional risk-weighting factors.

Estimated deferred taxes were based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the merger 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.

Goodwill As of December 31, 2009, the consolidated balance sheet included $758 million of goodwill, all of which has been assigned to the US reporting unit. Goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. We conduct the goodwill impairment test as of December 31 of each year. Other events and changes in circumstances may require goodwill to be tested for impairment between annual measurement dates. If the carrying value of goodwill is determined to be 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.

A 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. In determining 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. Downward revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in natural gas or crude oil 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 oil and gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves in place as of December 31, 2009; and estimates of operating, administrative and capital costs adjusted for inflation. We discounted the resulting future cash flows using a peer company based weighted average cost of capital of 10%.

Under the market approach, we estimated 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. At December 31, 2009, we used 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.

Using the range of US reporting unit fair values provided by the income and market approaches as of December 31, 2009, we determined that the fair value of our US reporting unit substantially exceeded its carrying amount. Therefore, the second step of the goodwill impairment test was unnecessary, and no goodwill impairment was recognized.

Although we have based 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 to be included in that carrying amount is based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. The 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.

Derivative Instruments and Hedging Activities In order to reduce 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 types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. In accordance with US GAAP for derivative instruments and hedging activities, all 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 $103 million at December 31, 2009. We estimated the fair values of our commodity derivative instruments in accordance with US GAAP for fair value measurements. 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. We compare our estimates of fair value with those provided by our counterparties. There have been no significant differences.

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, 2009, we reported a $110 million mark-to-market loss on commodity derivative instruments. See Item 7. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk and Item 8. Financial Statements and Supplementary Data – Note 6. Derivative Instruments and Hedging Activities.

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. US GAAP requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost 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 $232 million at December 31, 2009. See Item 8. Financial Statements and Supplementary Data – Note 10. Asset Retirement Obligations.

Involuntary Conversions When an involuntary conversion occurs, such as the destruction of oil and gas producing assets by a hurricane, a loss is accrued by a charge to income if the amount of loss can be reasonably estimated. An asset relating to insurance recovery is recognized only when realization of the claim for recovery of a loss recognized in the financial statements is deemed probable. A gain (recovery of a loss not yet recognized in the financial statements or an amount recovered in excess of a loss recognized in the financial statements) is not recognized until the insurance reimbursement has been received.

Management must make a number of estimates and assumptions relating to these gain and loss accruals. These include estimated costs of salvage, clean-up, restoration, redevelopment or abandonment and estimated amounts of insurance recoveries. The amount of an insurance recovery may be limited if total industry claims are in excess of the insurance carrier's ceiling limitation per event. A significant amount of time may be necessary for an insurance carrier to review all related claims for an event and determine the company-specific claim limitation on the final recovery. In addition, we may continue to incur costs, submit claims and receive reimbursements over a multi-year period.

The estimates involved in this process can have significant effects on reported amounts of net income. A decrease in the estimated amount of insurance recoveries will result in an increase in the involuntary conversion loss, which will result in a decrease in net income. An increase in estimated costs of salvage, if not covered by insurance, will also result in an increase in the involuntary conversion loss, which will result in a decrease in net income. Unreimbursed losses will have a negative effect on our cash flows. During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for damage related to Hurricanes Ivan in 2004 and Katrina in 2005. These factors included cost escalation due to weather delays and an increase in effort for the design and construction of the deck lifting barge and mooring system, as well as additional costs for the actual deck lifting activities. These increases caused the total project costs, combined with net book value of the assets destroyed, to exceed certain insurance coverage limitations. As a result, we recorded $51 million as a loss on involuntary conversion in 2007. In 2008, we recorded an additional $9 million loss on involuntary conversion upon resolution of certain of our insurance claims related to the hurricane damage sustained in 2005. In 2009, we recorded a net gain of $9 million representing receipt of insurance claims related to damage caused by Hurricanes Katrina and Rita. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies.

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.

The 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 return 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.

As of December 31, 2009, the accumulated undistributed earnings of our foreign subsidiaries on which no US taxes have been recorded totaled approximately $1.2 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 first quarter 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 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 Israel. However, we estimate that a repatriation of $1 billion as of December 31, 2009, if we had elected not to use the cash to fund international development, would have had a net cash tax impact of approximately $195 million. This amount is net of estimated foreign tax credits.

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 collectibility 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.

In 2008, we reduced the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser, by $38 million. We reduced the carrying value by an additional $12 million in 2009 when a settlement was reached and we received a distribution from SemCrude. See Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

Through December 31, 2008, we had recorded an allowance for doubtful accounts of $57 million related to our Ecuador power operations. The allowance was necessary to cover potentially uncollectible balances, as certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. As a result of pursuing various strategies to protect our interests, including international arbitration and litigation, we reached a settlement in fourth quarter 2008. In March and April 2009, we received total payments of $60 million in accordance with the terms of the settlement, against which a reserve of $46 million had previously been recorded. Accordingly, we reduced the allowance for doubtful accounts by $46 million and included the amount as a reduction in electricity generation expense in first quarter 2009.

The allowance for doubtful accounts totaled $31 million at December 31, 2009. See Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies – Allowance for Doubtful Accounts.

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 certain assumptions be made 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, 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, 2010, cumulative asset gains (losses) of approximately $(16) 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. We assume that the long-term asset mix will be consistent with the target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in asset allocation. A 1% decrease in the expected return on plan assets assumption would have increased 2009 net periodic benefit cost by approximately $2 million. The fair value of plan assets was $172 million at December 31, 2009. The expected return assumption used in the calculation of 2009 net periodic benefit cost was 8.00%. The assumption will be reduced to 7.50% for the calculation of 2010 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, 2009 discount rate, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) 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 assumption would have decreased 2009 net periodic benefit cost by $2 million and decreased the benefit obligation for the combined plans by $22 million at December 31, 2009. A 1% decrease in the discount rate assumption would have increased 2009 net periodic benefit cost by $2 million and increased the benefit obligation for the combined plans by $24 million at December 31, 2009. The assumed discount rate used to determine net periodic benefit cost for 2009 was 6.00% for the defined benefit pension and 6.25% for the restoration and medical and life plans. The assumed discount rate used to determine the benefit obligations at December 31, 2009 was 6.00% for the defined benefit pension and restoration plans and 5.50% for the medical and life plans. The total accrued benefit obligation for the defined benefit pension, restoration and medical and life plans was $251 million at December 31, 2009.

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, 2009, we had entered into variable to fixed price commodity swaps, 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 $103 million. Based on the December 31, 2009 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 $9 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 $12 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 6. Derivative Instruments and Hedging Activities.

As of December 31, 2009, a net unrealized loss of $12 million, net of tax, is recorded in AOCL in the consolidated balance sheets. We will reclassify all of the remaining deferred loss to earnings during 2010 as adjustments to revenue when the associated production occurs.

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, 2009, we had $2 billion (excluding unamortized discount) of long-term debt outstanding. Of this amount, $1.6 billion was fixed-rate debt with a weighted average interest rate of 7.73%. 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.

The remainder of our long-term debt, $382 million at December 31, 2009, was variable-rate debt. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the December 31, 2009 balance of our variable-rate debt would result in a change in annual interest expense of approximately $1 million.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. 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. At December 31, 2009, AOCL included $2 million, net of tax, related to interest rate locks. This amount is currently being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014. See Item 8. Financial Statements and Supplementary Data – Note 6. 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, 2009, our cash and cash equivalents totaled $1 billion with investments in money market funds and short-term deposits with major banking institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of December 31, 2009 would result in a change in annual interest income of approximately $2.5 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.

In the UK sector of our North Sea operations, significant future capital commitments and certain operating expenses are expected to be denominated in British pounds and/or the Euro. Therefore, our cash flows could be impacted by future changes in the exchange rate between the US dollar and the British pound and/or the Euro. We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, collars or swap agreements) in the future in order to mitigate our foreign currency exchange risk.

Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

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

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

As of December 31, 2009, 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, 2009, 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, 2009 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009. 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), the investment in which, as discussed in Note 11 of the consolidated financial statements, is accounted for by the equity method of accounting. The Company's investment in Alba at December 31, 2009 and 2008 was $111 million and $106 million, respectively, and its equity in earnings of Alba was $66 million, $118 million, and $128 million for the years ended December 31, 2009, 2008, and 2007, respectively. The financial statements of Alba were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Alba, is based solely on the reports 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 and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, 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, 2009, 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 18, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 18, 2010

Report of Independent Registered Public Accounting Firm

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

We have audited Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2009, 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 18, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 18, 2010

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

	Year Ended December 31,		
	2009	2008	2007
Revenues			
Oil, Gas and NGL Sales	$2,060	$ 3,651	$ 2,966
Income from Equity Method Investees	84	174	211
Other Revenues	169	76	95
Total Revenues	2,313	3,901	3,272
Costs and Expenses			
Production Expense	525	594	488
Exploration Expense	144	217	219
Depreciation, Depletion and Amortization	816	791	736
General and Administrative	237	236	206
Asset Impairments	604	294	4
Other Operating Expense, Net	45	134	124
Total Operating Expenses	2,371	2,266	1,777
Operating Income (Loss)	(58)	1,635	1,495
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	110	(440)	(2)
Interest, Net of Amount Capitalized	84	69	113
Other Non-Operating (Income) Expense, Net	12	(55)	16
Total Other (Income) Expense	206	(426)	127
Income (Loss) Before Income Taxes	(264)	2,061	1,368
Income Tax Provision (Benefit)	(133)	711	424
Net Income (Loss)	$ (131)	$ 1,350	$ 944
Earnings (Loss) Per Share, Basic	$ (0.75)	$ 7.83	$ 5.52
Earnings (Loss) Per Share, Diluted	(0.75)	7.58	5.45
Weighted Average Number of Shares Outstanding, Basic	173	173	171
Weighted Average Number of Shares Outstanding, Diluted	173	176	173

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

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

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,014	$ 1,140
Accounts Receivable, Net	465	423
Commodity Derivative Assets, Current	13	437
Other Current Assets	186	158
Total Assets, Current	1,678	2,158
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	12,584	11,963
Property, Plant and Equipment, Other	240	175
Total Property, Plant and Equipment, Gross	12,824	12,138
Accumulated Depreciation, Depletion and Amortization	(3,908)	(3,134)
Total Property, Plant and Equipment, Net	8,916	9,004
Goodwill	758	759
Other Noncurrent Assets	455	463
Total Assets	$ 11,807	$ 12,384
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 548	$ 579
Other Current Liabilities	442	595
Total Liabilities, Current	990	1,174
Long-Term Debt	2,037	2,241
Deferred Income Taxes, Noncurrent	2,076	2,174
Other Noncurrent Liabilities	547	486
Total Liabilities	5,650	6,075
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; 194 Million and 192 Million Shares Issued, Respectively	645	641
Additional Paid in Capital	2,260	2,193
Accumulated Other Comprehensive Loss	(75)	(110)
Treasury Stock, at Cost; 19 Million Shares	(615)	(614)
Retained Earnings	3,942	4,199
Total Shareholders' Equity	6,157	6,309
Total Liabilities and Shareholders' Equity	$ 11,807	$ 12,384

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

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

	Year Ended December 31,		
	2009	2008	2007
Cash Flows From Operating Activities			
Net Income (Loss)	$ (131)	$ 1,350	$ 944
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	816	791	736
Dry Hole Expense	11	84	90
Asset Impairments	604	294	4
Deferred Income Taxes	(296)	359	292
Income from Equity Method Investees	(84)	(174)	(211)
Dividends from Equity Method Investees	92	221	227
Unrealized (Gain) Loss on Commodity Derivative Instruments	606	(522)	(2)
Settlement of Previously Recognized Hedge Losses	-	(194)	(183)
Allowance for Doubtful Accounts	(18)	49	14
Net Gain on Asset Sales	(22)	(5)	(12)
(Gain) Loss on Involuntary Conversion	(9)	9	51
Other Adjustments for Noncash Items Included in Income	86	26	91
Changes in Operating Assets and Liabilities			
(Increase) Decrease in Accounts Receivable	(28)	121	(22)
(Increase) Decrease in Other Current Assets	(4)	(17)	116
Increase (Decrease) in Accounts Payable	(19)	(142)	19
Increase (Decrease) in Other Current Liabilities	(38)	67	(158)
Increase (Decrease) in Other Operating Assets and Liabilities, Net	(58)	(32)	21
Net Cash Provided by Operating Activities	1,508	2,285	2,017
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(1,268)	(1,971)	(1,414)
Acquisitions, Net of Cash Acquired	-	(292)	-
Proceeds from Sale of Property, Plant and Equipment, and Other	3	131	11
Net Cash Used in Investing Activities	(1,265)	(2,132)	(1,403)
Cash Flows From Financing Activities			
Exercise of Stock Options	17	27	25
Excess Tax Benefits from Stock-Based Awards	5	24	20
Dividends Paid, Common Stock	(126)	(115)	(75)
Purchase of Treasury Stock	(1)	(3)	(102)
Proceeds from Credit Facilities	340	951	280
Repayment of Credit Facilities	(1,564)	(525)	(255)
Proceeds from Issuance of Senior Long-Term Debt	989	-	-
Repayment of Installment Note	(25)	(25)	-
Repurchase of Senior Debentures	(4)	(7)	-
Net Cash Provided by (Used in) Financing Activities	(369)	327	(107)
Increase (Decrease) in Cash and Cash Equivalents	(126)	480	507
Cash and Cash Equivalents at Beginning of Period	1,140	660	153
Cash and Cash Equivalents at End of Period	$ 1,014	$ 1,140	$ 660

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

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

	Year Ended December 31,		
	2009	2008	2007
Common Stock			
Balance, Beginning of Period	$ 641	$ 636	$ 629
Exercise of Stock Options	2	4	5
Restricted Stock Awards, Net	2	1	2
Balance, End of Period	645	641	636
Capital in Excess of Par Value			
Balance, Beginning of Period	2,193	2,106	2,041
Stock-Based Compensation Expense	49	39	27
Exercise of Stock Options	15	23	20
Tax Benefits Related to Exercise of Stock Options	5	24	20
Restricted Stock Awards, Net	(2)	(1)	(2)
Rabbi Trust Shares Sold	-	2	-
Balance, End of Period	2,260	2,193	2,106
Accumulated Other Comprehensive Loss			
Balance, Beginning of Period	(110)	(284)	(140)
Oil and Gas Cash Flow Hedges			
Realized Amounts Reclassified Into Earnings	36	207	33
Unrealized Change in Fair Value	-	-	(184)
Net Change in Other	(1)	(33)	7
Balance, End of Period	(75)	(110)	(284)
Treasury Stock at Cost			
Balance, Beginning of Period	(614)	(613)	(511)
Purchases of Treasury Stock	(1)	(3)	(102)
Rabbi Trust Shares Sold	-	2	-
Balance, End of Period	(615)	(614)	(613)
Retained Earnings			
Balance, Beginning of Period	4,199	2,964	2,095
Net Income (Loss)	(131)	1,350	944
Cash Dividends ($0.720, $0.660 and $0.435 Per Share, Respectively)	(126)	(115)	(75)
Balance, End of Period	3,942	4,199	2,964
Total Shareholders' Equity	$ 6,157	$6,309	$4,809

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

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

	Year Ended December 31,		
	2009	2008	2007
Net Income (Loss)	$ (131)	$ 1,350	$ 944
Other Items of Comprehensive Income (Loss)			
Oil and Gas Cash Flow Hedges			
Realized Losses Reclassified Into Earnings	58	331	54
Less Tax Benefit	(22)	(124)	(21)
Unrealized Change in Fair Value	-	-	(295)
Less Tax Benefit	-	-	111
Net Change in Other	(2)	(52)	11
Less Tax Provision (Benefit)	1	19	(4)
Other Comprehensive Income (Loss)	35	174	(144)
Comprehensive Income (Loss)	$ (96)	$ 1,524	$ 800

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

Note 1. Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is an independent energy company engaged in worldwide crude oil, natural gas and natural gas liquids (NGLs) exploration and production. We operate primarily in the Rocky Mountains, Mid-continent, and deepwater Gulf of Mexico areas in the US, with key international operations offshore Israel and West Africa.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to accounting principles generally accepted in the US. 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 11. 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 accounting principles generally accepted in the 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.

Estimates of crude oil and natural gas reserves are the most significant of our estimates. All of the reserves data 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, Denver and London 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. Current credit market conditions combined with volatile commodity prices have resulted in increased uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined accurately, actual results could differ significantly from our estimates.

Reclassification Certain reclassifications have been made to the 2008 and 2007 consolidated financial statements to conform to the 2009 presentation. These reclassifications were not material to the 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, to drill and equip exploratory wells that find proved reserves and to 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 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 proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserves estimates or sustained decrease in commodity prices. We estimate the 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 amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, available market data associated with the property or similar properties, future commodity prices and operating expenses, timing of future production, future capital expenditures and a risk-adjusted discount rate.

Due to the declines in commodity prices which occurred during fourth quarter 2008 and continued in first quarter 2009, we assessed the recoverability of our proved oil and gas properties and other long-lived assets and recorded impairment charges. Additional impairment charges were recorded at December 31, 2009. See Note 3. Asset Impairments. In 2007, we recorded impairment charges of $4 million, primarily related to downward reserve revisions on US properties and/or adjustment of the carrying value of properties to their fair values. It is reasonably possible that other proved oil and gas properties or long-lived assets could become impaired in the future if commodity prices decline.

Unproved Property Impairment We assess individually significant unproved properties for impairment of value 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 exploratory 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 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 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.

During fourth quarter 2008, due to declines in commodity prices, we assessed the recoverability of our individually significant unproved oil and gas properties and recorded impairment charges. See Note 3. Asset Impairments. In 2009, no impairment charges were recorded. In 2007, we recorded $3 million of impairment charges for individually significant unproved properties and included the amounts in exploration expense. It is reasonably possible that other individually significant unproved oil and gas properties could become impaired in the future if commodity prices decline.

Properties Acquired in Business Combinations In determining the fair values of proved and unproved properties acquired in business combinations, 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 the fair value assigned to 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 business combination. 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.

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 7. Capitalized Exploratory Well Costs.

Other Property Other property includes automobiles, trucks, airplane, office furniture and 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 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 $45 million in 2009, $33 million in 2008, and $17 million in 2007.

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.

Revenues derived from electricity generation are recognized when power is transmitted or delivered, the price is fixed and determinable and collectibility is reasonably assured.

We also engage in the purchase and sale of third-party crude oil and natural gas. We record third-party sales, net of cost of goods sold, as gathering, marketing and processing revenues when the product is delivered or the contract is net settled at a fixed or determinable price, title has transferred and collectibility is reasonably assured. Gathering, marketing and processing revenues are included in other revenues in the consolidated statements of operations.

Fair Value Measurements US GAAP for fair value measurements establishes a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value. See Note 5. Fair Value Measurements and Disclosures.

Derivative Instruments and Hedging Activities In order to reduce 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. The derivative instruments we use include variable to fixed price commodity swaps, collars and basis swaps. We account for derivative instruments and hedging activities in accordance with US GAAP for derivative instruments and hedging activities. All derivative instruments (including certain derivative instruments embedded in other contracts) must be recorded on the balance sheet as either an asset or liability measured at fair value. Changes in a derivative instrument's fair value must be 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 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. Gains and losses from derivative instruments related to future crude oil and natural gas sales and which qualify for hedge accounting treatment are recorded in oil and gas sales in the consolidated statements of operations upon sale of the associated commodity.

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 and using regression analysis. A hedge is considered effective if certain statistical tests are met. We record hedge ineffectiveness in (gain) loss on commodity derivative instruments. See Note 6. Derivative Instruments and Hedging Activities.

Through December 31, 2007, we elected to designate the majority of our crude oil and natural gas derivative instruments as cash flow hedges. Effective January 1, 2008, we voluntarily discontinued cash flow hedge accounting on all existing commodity derivative instruments. We voluntarily made this change to simplify the accounting for our commodity hedge program as well as to add more transparency in related disclosures for the benefit of our investors. From January 1, 2008 forward, we recognize all gains and losses on such instruments in earnings in the period in which they occur. Net derivative losses that were deferred in AOCL as of December 31, 2007, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur. The discontinuance of cash flow hedge accounting for commodity derivative instruments did not affect our net assets or cash flows at December 31, 2007 and did not require adjustments to our previously reported financial statements.

Goodwill Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is not amortized to earnings but is tested annually in the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. No goodwill impairment was indicated as of December 31, 2009. However, it is reasonably possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

We reduced the amount of goodwill originally recorded by $1 million in 2009 and $2 million in 2008 for deferred tax assets associated with the exercise of fully-vested stock options assumed in conjunction with the Patina Merger. Reductions are recorded to the extent that the stock-based compensation expense reported for tax purposes does not exceed the fair value of the awards recognized as part of the total purchase price. In 2010, the remainder of these options will expire and will no longer have an impact on our goodwill.

Stock-Based Compensation We recognize the grant-date fair value of stock options and other stock-based compensation issued to employees in the statement of operations. Expense is recognized on a straight-line basis over the employee's requisite service period (generally the vesting period of the award). See Note 13. 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 returns 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.

Statements of Operations Information Additional statements of operations information is as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Other Revenues			
Refund of Deepwater Gulf of Mexico Royalties [1]	$ 86	$ -	$ -
Electricity Sales [2]	72	56	71
Gathering, Marketing and Processing (GMP) Revenues	11	20	24
Total	$ 169	$ 76	$ 95
Production Expense			
Lease Operating Expense	$ 372	$ 371	$ 322
Production and Ad Valorem Taxes	94	166	114
Transportation Expense	59	57	52
Total	$ 525	$ 594	$ 488
Other Operating Expense, Net			
Net Gain on Asset Sales [3]	$ (22)	$ (5)	$ (12)
Electricity Generation Expense [2]	18	57	57
GMP Expense	18	19	17
Settlement of Legal Proceedings [4]	9	1	(1)
(Gain) Loss on Involuntary Conversion [5]	(9)	9	51
Other, Net [6]	31	53	12
Total	$ 45	$ 134	$ 124
Other Non-Operating (Income) Expense, Net			
Deferred Compensation (Income) Expense [7]	$ 23	$ (32)	$ 33
Interest Income [8]	(13)	(20)	(19)
Other (Income) Expense, Net	2	(3)	2
Total	$ 12	$ (55)	$ 16

(1) See Refund of Deepwater Gulf of Mexico Royalties below.

(2) Includes amounts related to our 100%-owned Ecuador integrated power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel 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. We recognized a net decrease of $32 million in the allowance in 2009, and net increases of $11 million in 2008 and $14 million in 2007. See Allowance for Doubtful Accounts below.

(3) Includes $24 million gain on sale of our interest in Argentina. In February 2008, effective July 1, 2007, we sold our interest in Argentina for a sales price of $117.5 million. Recognition of the gain on the sale was deferred until second quarter 2009 when the Argentine government approved the sale.

(4) The amount for 2009 includes a $19 million charge on legal settlement, offset by a $15 million gain on legal settlement related to reimbursement of bonuses paid for federal leases offshore California.

(5) The amount for 2009 represents receipt of insurance claims related to Hurricanes Katrina and Rita damage. The amount for 2008 represents interim settlement of the replacement cost portion of the Hurricane Katrina insurance claim. The amount for 2007 represents project costs in excess of certain insurance coverage limitations related to hurricane cleanup costs at our Gulf of Mexico Main Pass asset.

(6) Includes write-downs of SemCrude L.P. (SemCrude) receivable of $12 million in 2009 and $38 million in 2008. SemCrude was a purchaser of our crude oil. See Allowance for Doubtful Accounts below and Note 17. Commitments and Contingencies.

(7) The amount represents increases (decreases) in the fair value of shares of our common stock held in a rabbi trust. See Note 12. Benefit Plans.

(8) Includes $11 million interest income related to expected refund of deepwater Gulf of Mexico royalties. See Refund of Deepwater Gulf of Mexico Royalties below.

Balance Sheet Information Additional balance sheet information is as follows:

	December 31,	
	2009	2008
(millions)		
Accounts Receivable, Net		
Commodity Sales	$ 205	$ 296
Joint Interest Billings	140	87
Refund of Deepwater Royalties [1]	97	-
Marketing and Trading Activities	25	130
Other	29	7
Allowance for Doubtful Accounts [2]	(31)	(97)
Total	$ 465	$ 423
Other Current Assets		
Inventories, Current	$ 89	$ 105
Prepaid Expenses and Other Assets, Current	65	27
Deferred Income Taxes, Net, Current	32	-
Asset Held for Sale [3]	-	26
Total	$ 186	$ 158
Other Noncurrent Assets		
Equity Method Investments	$ 303	$ 311
Mutual Fund Investments	108	84
Commodity Derivative Assets, Noncurrent	1	33
Other Assets, Noncurrent	43	35
Total	$ 455	$ 463

(1) See Refund of Deepwater Gulf of Mexico Royalties below.
(2) See Allowance for Doubtful Accounts below.
(3) Our remaining non-core Gulf of Mexico shelf asset at Main Pass was reclassified from held-for-sale to held-and-used and impaired during first quarter 2009. See Note 3. Impairments and Note 4. Acquisitions and Divestitures.

(millions)	December 31, 2009	December 31, 2008
Accounts Payable - Trade		
Capital Costs	$ 277	$ 273
Royalties Payable	65	81
Marketing and Trading Activities	76	159
Lease Operating Expense	27	10
Other	103	56
Total	$ 548	$ 579
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 103	$ 114
Commodity Derivative Liabilities, Current	100	23
Income Taxes Payable	60	130
Deferred Income Taxes, Net, Current	1	142
Asset Retirement Obligations, Current	51	27
Interest Payable	37	9
Short-Term Borrowings	-	25
Deferred Gain on Asset Sale, Current [1]	-	24
Other	90	101
Total	$ 442	$ 595
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 213	$ 159
Asset Retirement Obligations, Noncurrent	181	184
Accrued Benefit Costs, Noncurrent	76	81
Commodity Derivative Liabilities, Noncurrent	17	2
Other	60	60
Total	$ 547	$ 486

[1] See footnote (3) to *Statements of Operations Information* above.

Statements of Cash Flows and Supplementary Disclosures of Cash Flow Information 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. Additional cash flow information is as follows:

(millions)	Year Ended December 31, 2009	2008	2007
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 52	$ 76	$ 105
Income Taxes Paid, Net	227	263	149
Non-Cash Financing and Investing Activities			
Increase in Long-Term Obligation Related to FPSO Construction	29	-	-
Issuance of Notes for Property Interests	-	-	50

Refund of Deepwater Gulf of Mexico Royalties On October 5, 2009, the US Supreme Court denied a petition filed by the US Department of the Interior (DOI) in a case styled *Dept. of Interior, et al v. Kerr-McGee Oil and Gas Corp.* (09-54). This case involved the payment of royalties attributable to federal leases acquired by Kerr-McGee Oil and Gas Corporation (Kerr-McGee) pursuant to Section 304 of the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (DWRRA). As a result of the Supreme Court's decision, lower court rulings from the US District Court of the Western District of Louisiana and US Court of Appeals for the Fifth Circuit, which were in favor of Kerr-McGee, were left to stand. Those courts ruled that the DOI did not have the authority to impose price thresholds that required the payment of royalties before minimum royalty suspension volumes imposed by Section 304 of the DWRRA were produced.

Based upon our analysis of the Kerr-McGee case, we believe that the Supreme Court's decision impacts other companies, including us, who were not directly involved in the case but, like Kerr-McGee, acquired leases issued pursuant to Section 304 of the DWRRA. As a result, we believe that we are entitled to a refund of approximately $86 million plus interest of $11 million. The refund is attributable to royalties that we previously paid on production of approximately 900 MBbls of crude oil and 3,000 MMcf of natural gas that were produced from January 1, 2003 through July 31, 2009. We have requested a refund from the MMS and anticipate receiving the refund in 2010.

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. Changes in the allowance for doubtful accounts were as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Balance, Beginning of period	$ 97	$ 50	$ 35
Changes			
Allowance for SemCrude receivable	12	38	-
Allowance for Ecuador receivable	14	11	14
Recovery of Ecuador receivable	(46)	-	-
Other Changes	2	-	-
Net Changes Before Write-offs	(18)	49	14
Write-off of SemCrude receivable	(49)	-	-
Other Write-offs	1	(2)	1
Balance, End of Period	$ 31	$ 97	$ 50

For a discussion of the SemCrude matter, see Note 17. Commitments and Contingencies.

Through December 31, 2008, we had recorded an allowance for doubtful accounts of $57 million related to our Ecuador power operations. The allowance was necessary to cover potentially uncollectible balances, as certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. As a result of pursuing various strategies to protect our interests, including international arbitration and litigation, we reached a settlement in fourth quarter 2008. In March and April 2009, we received total payments of $60 million in accordance with the terms of the settlement, against which a reserve of $46 million had previously been recorded. Accordingly, we reduced the allowance for doubtful accounts by $46 million and included the amount as a reduction in electricity generation expense in first quarter 2009. We recorded an additional allowance of $14 million related to current period electricity sales in 2009.

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 expense.

Inventories consisted of the following:

	December 31,	
	2009	2008
(millions)		
Materials and Supplies	$ 71	$ 92
Crude Oil	18	13
Total	$ 89	$ 105

Basic and Diluted Earnings Per Share Basic earnings per share (EPS) of our common stock have been 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. See Note 14. Earnings Per Share.

Related Party Transactions Following the Patina Merger in 2005, we entered into a consulting agreement with a former officer of Patina who now serves as a member of our Board of Directors. Pursuant to the consulting agreement, we reimbursed his office space rent of $42,000 in 2007.

Contingencies We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See Note 17. Commitments and Contingencies.

We self-insure the medical and dental coverage provided to certain employees, certain workers' compensation and the first $1 million of 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.

Concentration of Market Risk In 2009, Glencore Energy UK Ltd was the largest single non-affiliated purchaser of production and accounted for 25% of crude oil sales, or 16% of total oil, gas and NGL sales. In 2008, Suncor Energy Marketing was the largest single non-affiliated purchaser of production and accounted for 22% of crude oil sales, or 13% of total oil, gas and NGL sales. In 2007, Marathon Petroleum Supply Company was the largest single non-affiliated purchaser of production and accounted for 18% of crude oil sales, or 10% of total oil, gas and NGL sales. 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. Substantially all of our cash at December 31, 2009 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 electricity, and joint interest billings to our partners. The receivables 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 international 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. In third quarter 2008, we reduced the carrying value of a receivable from SemCrude and recognized a pre-tax charge of $38 million for a probable loss. We recorded an additional reduction in the carrying value of the SemCrude receivable, and corresponding pre-tax charge, of $12 million in 2009. See Note 17. Commitments and Contingencies. See also Allowance for Doubtful Accounts, above, for a discussion of accounts receivable from sales of electricity.

We use crude oil and natural gas derivative instruments to mitigate the effects of commodity price fluctuations and these derivative instruments expose us to counterparty credit risk. Our counterparties are major banks or financial institutions. 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.

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 as well as incur a loss. See Note 6. Derivative Instruments and Hedging Activities.

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

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.

Recently Adopted Standards The following standards have been adopted:

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. The most significant amendments to the requirements included the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows is now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserves Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years.
- Reserves Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Disclosure by Geographic Area – Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and gas proved reserves.
- Non-Traditional Resources – The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009. See Supplemental Oil and Gas Information (Unaudited) for impact of adoption on oil and gas reserves.

In addition, in January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (Update) 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. The Update amends 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 are applied prospectively as a change in estimate. See also Supplemental Oil and Gas Information (Unaudited).

Postretirement Benefit Plan Asset Disclosures In December 2008, the FASB issued new standards which require employers to make additional disclosures about plan assets for defined benefit pension and other postretirement benefit plans beginning with annual periods ending after December 15, 2009. Disclosures must provide an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair-value measurements using significant unobservable inputs on changes in plan assets for the period, and significant concentrations of risk within plan assets. We adopted the new standards as of December 31, 2009. Adoption of the new standards had no impact on our financial position or results of operations. See Note 12. Benefit Plans.

Business Combinations and Noncontrolling Interests in Consolidated Financial Statements In 2007, the FASB issued new standards regarding the accounting for business combinations and noncontrolling interests in consolidated financial statements. These standards require most identifiable assets, liabilities and noncontrolling interests to be recorded at full fair value and require noncontrolling interests to be reported as a component of equity. We adopted the new standards as of January 1, 2009. There were no non-controlling interests at adoption date. Adoption of the new standards had no impact on our financial position or results of operations.

Fair Value Measurements The FASB's fair value measurement standards establish a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and create a fair value hierarchy that prioritizes the information used to develop those assumptions. The standards require additional disclosures, including disclosures of fair value measurements by level within the fair value hierarchy. As of January 1, 2008, we adopted the new standards as they related to our financial assets and liabilities. As of January 1, 2009, we adopted the new standards as they related to our nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill impairment; and initial recognition of asset retirement obligations. Adoption of the new standards did not have a significant impact on our consolidated financial statements.

In April 2009, the FASB issued additional guidance clarifying the application of US GAAP for fair value measurements in the current economic environment, modifying the recognition of other-than-temporary impairments of debt securities, and requiring companies to disclose the fair value of financial instruments in interim periods. The revised guidance was effective for interim and annual periods ending after June 15, 2009. The guidance:

- describes how to determine the fair value of assets and liabilities in the current economic environment and reemphasizes that the objective of a fair value measurement remains the price that would be received to sell an asset or paid to transfer a liability at the measurement date;
- modifies the requirements for recognizing other-than-temporarily impaired debt securities and significantly changes the existing impairment model for such securities. It also modifies the presentation of other-than-temporary impairment losses and increases the frequency of and expands already required disclosures about other-than-temporary impairment for debt and equity securities; and
- requires disclosures of the fair value of financial instruments in interim financial statements, the method or methods and significant assumptions used to estimate the fair value of financial instruments, and a discussion of changes, if any, in the method or methods and significant assumptions during the period.

We adopted this new guidance for the quarter ended June 30, 2009. Adoption of the new guidance had no impact on our financial position or results of operations.

In August 2009, the FASB issued Accounting Standards Update 2009-5, "Measuring Liabilities at Fair Value" in order to provide further guidance on how to measure the fair value of a liability. The Update clarifies that, in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more prescribed techniques. We adopted the new guidance as of October 1, 2009. Adoption of the new guidance had no impact on our financial position or results of operations.

See Note 5. Fair Value Measurements and Disclosures.

Fair Value Option Under US GAAP for fair value measurements, companies have an option to report selected financial assets and liabilities at fair value. We adopted the new guidance for optional fair value measurements as of January 1, 2008. Adoption of the new guidance had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

Derivative Instruments and Hedging Activities In March 2008, the FASB issued new standards which amended and expanded previous disclosure requirements related to derivative instruments and hedging activities. The new standards require qualitative disclosures about objectives and strategies for using derivative instruments, quantitative disclosures about fair value amounts of derivative instruments and related gains and losses, and disclosures about credit risk-related contingent features in derivative agreements. We adopted the new standards as of January 1, 2009. They provide only for enhanced disclosures, and adoption of the new standards had no impact on our financial position or results of operations. See Note 6. Derivative Instruments and Hedging Activities.

Subsequent Events In May 2009, the FASB issued new standards which establish the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. In particular, the new standards set forth:

- the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements (through the date that the financial statements are issued or are available to be issued);
- the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and
- the disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

We adopted the new standards as of June 30, 2009. We have evaluated subsequent events after the balance sheet date of December 31, 2009 through the time of filing with the SEC on February 18, 2010, which is the date the financial statements were issued. See Note 4. Acquisitions and Divestitures – *Pending Asset Acquisition* and Note 6. Derivative Instruments and Hedging Activities – *Interest Rate Hedges.*

Accounting Standards Codification In June 2009, the FASB established the FASB Accounting Standards Codification (Codification), which officially commenced July 1, 2009, to become the source of authoritative US GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative US GAAP for SEC registrants. Generally, the Codification is not expected to change US GAAP. All other accounting literature excluded from the Codification will be considered nonauthoritative. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the new standards for our quarter ending September 30, 2009. All references to authoritative accounting literature are now referenced in accordance with the Codification.

Equity Method Investments In November 2008, the FASB issued new guidance in accounting for equity method investments. The new guidance was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of new business combination standards. The new guidance concluded that equity method investments should continue to be recognized using a cost accumulation model, thus continuing to include transaction costs in the carrying amount of the equity method investment. In addition, it clarified that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. We adopted the new guidance as of January 1, 2009. Adoption of the new guidance had no impact on our financial position or results of operations.

Offsetting of Amounts Related to Certain Contracts As of January 1, 2008 we adopted guidance allowing companies to offset 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. Upon adoption of the new guidance, we elected to offset the right to reclaim cash collateral or the obligation to return cash collateral against our net derivative positions for which master netting agreements exist. As of December 31, 2009 and 2008, we had no significant cash collateral obligations.

Accounting for Uncertainty in Income Taxes As of January 1, 2007, we adopted new standards which clarified the accounting for uncertainty in income taxes recognized in a company's financial statements. The new standards prescribed a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. They also provided guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Also as of January 1, 2007, we adopted related guidance regarding the definition of "settlement". This guidance provided that a company's tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future.

Adoption of the new guidance had no effect on our financial position or results of operations. See Note 9. Income Taxes.

Note 3. Asset Impairments

2009 Asset Impairments Pre-tax (non-cash) impairments for 2009 totaled $604 million and related to the following proved oil and gas properties and investments:

- $389 million related to Granite Wash, an onshore US development;
- $48 million related to Main Pass, our remaining operated Gulf of Mexico shelf asset;
- $44 million related to Paxton, an onshore US development;
- $23 million related to Raton, a deepwater Gulf of Mexico development; and
- $100 million related to our investment in Ecuador.

US Oil and Gas Assets As a result of a significant decline in the forward natural gas price curve at March 31, 2009, we reviewed our oil and gas properties that are sensitive to natural gas price decreases for impairment. We determined that the carrying amount of Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, was not recoverable from future cash flows and, therefore, was impaired at March 31, 2009. We reduced Granite Wash to its fair value, using a discounted cash flow method, as comparable market data was not available. We also impaired our Main Pass asset in the Gulf of Mexico, which had been reclassified from held-for-sale to held-and-used.

At December 31, 2009, we reviewed our significant properties for impairment and recorded impairment charges on two additional properties. We determined that Paxton, an onshore US development was impaired primarily due to decreases in the forward natural gas price curve. We also impaired Raton, a deepwater Gulf of Mexico development primarily due to well performance issues. We reduced these properties to their fair values, using a discounted cash flow method, as comparable market data was not available.

Our US proved properties (including our Main Pass asset) were tested for impairment in 2009 in accordance with US GAAP for impairment or disposal of long-lived assets. 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.

Investment in Ecuador As a result of the increasingly unsettled economic and political environment in Ecuador, we also reviewed our investment in Ecuador for impairment as of December 31, 2009. We are aware that the Government of Ecuador is taking steps to renegotiate contracts or, in some cases, remove international oil and gas companies from its borders. In recent years, certain international companies have been subject to expropriation, forced to abandon their oil and gas assets, or bought out of their government contracts. On August 24, 2009, Ecuador's National Bureau of Hydrocarbons (DNH) rejected our third and most recent proposed plan of development for the Amistad field in Block 3, offshore Ecuador and noted that it was treating the plan of development as if it had not been received. We appealed the decision of the DNH, and it dismissed our appeal on November 11, 2009. On November 12, 2009, Empresa Estatal Petroleos Del Ecuador (Petroecuador) initiated the procedure of *caducidad* (or termination) by providing us with a notice that alleged 15 instances of non-compliance with the production sharing contract for Block 3 (PSC). On November 24, 2009, we responded to Petroecuador noting that its allegations had previously been resolved in our favor or otherwise addressed. Nevertheless, on December 31, 2009, Petroecuador requested that Ecuador's Minister of Non-Renewable Natural Resources commence termination of the PSC on the basis of the foregoing allegations and because a plan of development had not been approved. On February 11, 2010, the Minister notified us of Petroecuador's request, by delivering to us a copy of a letter of non-compliance dated December 31, 2009. The Minister provided us with 60 business days to respond to the allegations contained in the letter. We intend to vigorously act to protect our interests, and are evaluating appropriate action.

We determined that the carrying value of our investment in Ecuador exceeded its fair value by $100 million and we recorded an impairment charge for this amount in fourth quarter 2009. At December 31, 2009, we estimated the fair value of our investment in Ecuador 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. Future estimates of fair value may change, which could result in additional impairment charges. Our investment in Ecuador had a net book value of approximately $72 million after the December 31, 2009 impairment.

See also Note 5. Fair Value Measurements.

2008 Asset Impairments As a result of the depressed economic environment, coupled with a severe decrease in commodity prices during the fourth quarter of 2008, we assessed the recoverability of our proved and unproved oil and gas properties and other investments as of December 31, 2008. As a result, we determined that certain of our assets were impaired. In addition, during third quarter 2008, we recorded an impairment charge related to our Main

Pass asset based on anticipated sales proceeds less costs to sell. Total pre-tax (non-cash) impairment charges for 2008 were $294 million, as follows:

- $111 million related to various US proved oil and gas properties;
- $70 million related to our investment in Ecuador;
- $75 million related to various US unproved properties; and
- $38 million related to the Main Pass asset held for sale.

The impairments of unproved US oil and gas properties in 2008 were primarily related to allocated fair values attributable to probable and possible reserves acquired in previous business combinations. We assessed these properties using discounted cash flow models based on management's assumptions of future production, commodity prices, operating and development costs, and discount rates.

Our US proved properties and investment in Ecuador were tested for impairment in 2008 in accordance with US GAAP for impairment or disposal of long-lived assets. 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.

Note 4. Acquisitions and Divestitures

Mid-continent Acquisition In July 2008, we acquired producing properties in western Oklahoma for $292 million. The total purchase price was allocated to the proved and unproved properties acquired based on fair values at the acquisition date. Approximately $254 million was allocated to proved properties and $38 million to unproved properties.

Sale of Argentina Assets In February 2008, effective July 1, 2007, we sold our interest in Argentina for a sales price of $117.5 million. The sale was subject to Argentine government approval. The $24 million gain on sale was deferred in other current liabilities until second quarter 2009 when the Argentine government approved the sale.

Main Pass Asset In 2008, we initiated a process to sell our remaining operated non-core Gulf of Mexico shelf asset located at Main Pass. Numerous parties expressed an interest in purchasing the asset. However, due to difficulties in obtaining appropriate insurance, bonding or financing, none of the potential buyers were able to close on the sale. As a result, the asset was reclassified from held-for-sale to held-and-used in first quarter 2009. Due to significant increases in insurance costs and exposure to further windstorm damage, we are in the process of abandoning the Main Pass asset. See Note 3. Asset Impairments.

Pending Asset Acquisition On December 31, 2009, we entered into a definitive agreement to acquire substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for $494 million. The acquisition is expected to close late in the first quarter 2010 and is subject to customary closing conditions. Funding is expected to be provided through our existing credit facility.

Note 5. 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, collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 6. Derivative Instruments and Hedging Activities.

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

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

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Adjustment [1]	Fair Value Measurement
(millions)					
December 31, 2009					
Financial Assets					
Mutual Fund Investments	$ 108	$ -	$ -	$ -	$ 108
Commodity Derivative Instruments	-	42	-	(28)	14
Financial Liabilities					
Commodity Derivative Instruments	-	(145)	-	28	(117)
Patina Deferred Compensation Liability	(168)	-	-	-	(168)
December 31, 2008					
Financial Assets					
Mutual Fund Investments	$ 84	$ -	$ -	$ -	$ 84
Commodity Derivative Instruments	-	492	-	(22)	470
Financial Liabilities					
Commodity Derivative Instruments	-	(47)	-	22	(25)
Patina Deferred Compensation Liability	(123)	-	-	-	(123)

[1] 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. As of January 1, 2009, we adopted US GAAP fair value measurement standards as they related to our nonfinancial assets and liabilities.

The following methods and assumptions were used to estimate the fair values for nonrecurring measurements made in 2009:

Proved Property Impairments In accordance with US GAAP for the impairment or disposal of long-lived assets, we review a proved oil and gas property for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. We estimate the future cash flows expected in connection with the property and compare such future cash flows to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its 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.

Measurement information for proved properties measured at fair value on a nonrecurring basis in 2009 was as follows:

		Fair Value Measurements Using			
Description	Fair Value Measurement [1]	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Impairment Loss
(millions)					
Year Ended December 31, 2009					
Impaired US Oil and Gas Properties	$ 363	$ -	$ -	$ 363	$ 504
Impaired Investment in Ecuador	72	-	-	72	100

[1] Amount represents the fair values of the impaired properties as of the dates of the assessments, March 31, 2009 and December 31, 2009. See Note 3. Asset Impairments.

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 fair value of floating-rate debt is estimated using the carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 8. Debt.

Fair value information regarding our debt is as follows:

	December 31,			
	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount [1]	$ 2,008	$ 2,279	$ 2,266	$ 2,172

[1] Excludes obligation under FPSO lease.

Note 6. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments In order to reduce 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, collars and basis swaps. While these instruments mitigate the cash flow risk of future reductions in commodity prices they may also curtail benefits from future increases in commodity prices. We account for derivative instruments and hedging activities in accordance with US GAAP for derivative instruments and hedging activities, and all derivative instruments are reflected at fair value in our consolidated balance sheets. We elected to designate the majority of our commodity derivative instruments as cash flow hedges through December 31, 2007. As discussed in Note 2. Summary of Significant Accounting Policies – Derivative Instruments and Hedging Activities, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments effective January 1, 2008. See Note 5. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our commodity derivative instruments. See Note 2. Summary of Significant Accounting Policies – Concentration of Credit Risk for a discussion of counterparty credit risk.

Accounting for Commodity Derivative Instruments During 2009 and 2008, we accounted for our commodity derivative instruments using mark-to-market accounting, and we recognized all gains and losses on such instruments in earnings during the period in which they occur. Prior to January 1, 2008, we elected to designate certain of our commodity derivative instruments as cash flow hedges. Net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur. See Derivative Instruments in Previously Designated Cash Flow Hedging Relationships table below.

Unsettled Derivative Instruments As of December 31, 2009, we had entered into the following crude oil derivative instruments:

	Variable to Fixed Price Swaps			Collars			
Production Period	Index	Bbls Per Day	Weighted Average Fixed Price	Index	Bbls Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2010	NYMEX WTI	1,000	$ 78.70	NYMEX WTI	14,500	$ 61.48	$ 75.63
2010	Dated Brent	1,000	80.05	Dated Brent	7,000	64.00	73.96
2010 Average		2,000	79.38		21,500	62.30	75.09
2011	-	-	-	NYMEX WTI	6,000	79.00	87.42

From January 1, 2010 to February 5, 2010, we entered into additional NYMEX WTI swaps covering 2,000 Bbls per day for April through December 2010 with a weighted average fixed price of $85.69. We also entered into additional NYMEX WTI collars covering 2,000 Bbls per day for calendar year 2011 with weighted average floor and ceiling prices of $84.00 and $92.70, respectively.

As of December 31, 2009, we had entered into the following natural gas derivative instruments:

	Variable to Fixed Price Swaps			Collars			
Production Period	Index	MMBtu Per Day	Weighted Average Fixed Price	Index	MMBtu Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2010	NYMEX HH	20,000	$ 6.10	NYMEX HH [1]	210,000	$ 5.90	$ 6.73
2010	-	-	-	IFERC CIG [2]	15,000	6.25	8.10
2010 Average		20,000	6.10		225,000	5.93	6.82
2011	-	-	-	NYMEX HH	140,000	5.95	6.82

(1) Henry Hub
(2) Colorado Interstate Gas – Northern System

From January 1, 2010 to February 5, 2010, we entered into additional NYMEX HH swaps covering 20,000 MMBtu per day for April through December 2010, and 25,000 MMBtu per day for calendar year 2011 with weighted average fixed prices of $6.11 and $6.41, respectively.

As of December 31, 2009, we had entered into the following natural gas basis swaps:

	Basis Swaps			
Production Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2010	IFERC CIG	NYMEX HH	100,000	$ (1.60)
2011	IFERC CIG	NYMEX HH	110,000	(0.76)

From January 1, 2010 to February 5, 2010, we entered into an additional basis swap covering 10,000 MMBtu per day for April through December 2010 with a NYMEX HH to IFERC CIG differential of $(0.44).

The collar, fixed price swap 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 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 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, if any, 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, if any, of the fixed or floor price over the floating price in respect of each calculation period.

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Commodity Derivative Instruments Not Designated as Hedging Instruments

Asset Derivative Instruments				Liability Derivative Instruments			
December 31,				December 31,			
2009		2008		2009		2008	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)				*(millions)*			
Current Assets	$ 13	Current Assets	$ 437	Current Liabilities	$100	Current Liabilities	$ 23
Noncurrent Assets	1	Noncurrent Assets	33	Noncurrent Liabilities	17	Noncurrent Liabilities	2
Total	$ 14	Total	$ 470	Total	$117	Total	$ 25

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,		
	2009	2008	2007
(millions)			
Realized Mark-to-Market (Gain) Loss	$ (496)	$ 82	$ -
Unrealized Mark-to-Market (Gain) Loss	606	(522)	-
Ineffectiveness (Gain) Loss	-	-	(2)
Total (Gain) Loss on Commodity Derivative Instruments	$ 110	$ (440)	$ (2)

Derivative Instruments in Previously Designated 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		
	2009	2008	2007	2009	2008	2007
(millions)						
Commodity Derivative Instruments [1]						
Crude Oil [2]	$ -	$ -	$ 343	$ 58	$ 365	$ 223
Natural Gas [2]	-	-	(48)	-	(34)	(169)
Treasury Rate Locks	-	(1)	1	1	1	1
Total	$ -	$ (1)	$ 296	$ 59	$ 332	$ 55

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. Net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur.

(2) The amount of (gain) loss on derivative instruments reclassified from AOCL is recognized in oil, gas and NGL sales within our consolidated statements of operations.

AOCL As of December 31, 2009 and 2008, the balance in AOCL included net deferred losses of $12 million and $48 million, respectively, related to the fair value of crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefits of $7 million and $29 million, respectively. The net deferred losses (net of tax) related to the fair values of the commodity derivative instruments previously designated as cash flow hedges and remaining in AOCL at December 31, 2009 will be reclassified to earnings during the next 12 months as the forecasted transactions occur, and will be recorded as a reduction in oil and gas sales of approximately $20 million before tax. All forecasted commodity transactions currently being hedged are expected to occur by December 2010.

Interest Rate Hedges We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. 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. At December 31, 2009 and 2008, AOCL included deferred losses, net of tax, of $2 million and $3 million, respectively, related to interest rate swaps. This amount is being reclassified into earnings, at the rate of $0.8 million per year, as an adjustment to interest expense over the term of our 5¼% senior notes due 2014.

In 2007, we entered into two additional interest rate locks, each in the notional amount of $500 million. The locks were based on five and ten year US Treasury rates of 3.55% and 4.15%, respectively, and were scheduled to expire in September 2008. We settled the locks in July 2008 at a total cost of $0.2 million.

In January 2010, in anticipation of a long-term debt issuance, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on the anticipated debt issuance. We are accounting for the instrument as a cash flow hedge against the variability of interest payments attributable to changes in interest rates on the forecasted issuance of fixed-rate debt. The swap is in the notional amount of $500 million and is based on a 30-year LIBOR swap rate.

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, in which case 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,		
	2009	2008	2007
(millions)			
Capitalized Exploratory Well Costs, Beginning of Period	$ 501	$ 249	$ 80
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	136	253	182
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(198)	-	(7)
Capitalized Exploratory Well Costs Charged to Expense	(7)	(1)	(6)
Capitalized Exploratory Well Costs, End of Period	$ 432	$ 501	$ 249

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

	December 31,		
	2009	2008	2007
(millions)			
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 158	$ 256	$ 187
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	274	245	62
Balance at End of Period	$ 432	$ 501	$ 249
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	5	6	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 completion of drilling as of December 31, 2009:

		Suspended Since		
	Total	2008	2007	2006 & Prior
(millions)				
Project				
Blocks O and I (West Africa)	$ 172	$ 62	$ 96	$ 14
Gunflint (Deepwater Gulf of Mexico)	49	49	-	-
Redrock (Deepwater Gulf of Mexico)	17	-	-	17
Flyndre (North Sea)	15	-	12	3
Selkirk (North Sea)	21	-	21	-
Total Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	$ 274	$ 111	$ 129	$ 34

Blocks O and I (West Africa) The West Africa project includes Blocks O and I offshore Equatorial Guinea and the YoYo mining concession and Tilapia production sharing contract offshore Cameroon. Since drilling the initial well for this project, additional seismic work has been completed and exploration and appraisal wells have been drilled to further evaluate our discoveries. The West Africa development team is proceeding with a program to further define the resources in this area such that an optimal development program may be designed.

On July 22, 2009, we announced that the Plan of Development for the Aseng field (formerly Benita) on Block I has been sanctioned by us, our partners, and the Ministry of Mines, Industry, and Energy of the Republic of Equatorial Guinea. As a result, we reclassified $76 million of capitalized costs relating to the Aseng field out of capitalized exploratory well costs and into proved oil and gas properties.

We have evaluated the potential for additional liquids and gas projects, and expect that the next development will be at the Belinda field. Belinda project sanction is currently scheduled to occur in 2010 with production beginning in 2013. We are also evaluating future oil projects at Diega and Carmen and are currently scheduling first production for 2014, subject to sanctioning. In Cameroon, we will acquire a 3-D seismic survey over YoYo and portions of Tilapia during 2010, and exploration drilling is currently planned in Tilapia for 2011.

In addition to the remaining exploratory well costs that have been capitalized for a period greater than one year for the West Africa project, we have incurred $27 million in suspended costs related to additional drilling activity in West Africa through December 31, 2009.

Gunflint (Deepwater Gulf of Mexico) Gunflint (Mississippi Canyon Block 948) was a 2008 crude oil discovery and is our largest deepwater Gulf of Mexico discovery to date. We have acquired additional seismic information and are preparing to drill one or two appraisal wells in 2010.

Redrock (Deepwater Gulf of Mexico) Redrock (Mississippi Canyon Block 204) was a 2006 natural gas/condensate discovery and is currently considered a co-development candidate with South Raton (Mississippi Canyon Block 292). The anticipated development plan consists of tying South Raton back through the Gemini system to a host platform at Viosca Knoll Block 900 for processing and then connecting Redrock into this gathering system. Tie-back of Redrock is anticipated to occur following the development of South Raton.

Flyndre (North Sea) The Flyndre project is located in the UK sector of the North Sea and we successfully completed an exploratory appraisal well in 2007. We are currently working with the project operator and other partners to finalize the field development plan and relevant operating agreements.

Selkirk (North Sea) The Selkirk project is also located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an appraisal well which was then sidetracked to the original discovery well location, to ensure presence of effective reservoir, and suspended as a future producer. We are currently working with our partners on an alternative host and to reduce costs.

Note 8. Long-Term Debt

Our debt consists of the following:

	December 31,			
	2009		2008	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility [1]	$ 382	0.54%	$ 1,606	0.80%
5¼% Senior Notes, due April 15, 2014	200	5.25%	200	5.25%
8¼% Senior Notes, due March 1, 2019	1,000	8.25%	-	-
7¼% Notes, due October 15, 2023	100	7.25%	100	7.25%
8% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
7¼% Senior Debentures, due August 1, 2097	84	7.25%	89	7.25%
Obligation Under FPSO Lease [2]	29	-	-	-
Long-term Debt	2,045		2,245	
Installment Payment, due May 11, 2009	-	-	25	4.18%
Total Debt	2,045		2,270	
Unamortized Discount	(8)		(4)	
Total Debt, Net of Discount	$ 2,037		$ 2,266	

(1) We expect to use the credit facility to fund our planned $494 million acquisition of US Rocky Mountain assets in the first quarter 2010. See Note 4. Acquisitions and Divestitures – Pending Asset Acquisition.

(2) Amount reported is based on percentage of FPSO construction activities completed as of December 31, 2009 and therefore does not reflect future minimum lease obligations. See *Obligation Under FPSO Lease* below.

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 $13 million remain and are being amortized to expense over the life of the related debt issues.

Credit Facility Our bank revolving credit facility (the credit facility) is committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are 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 credit facility. The credit facility requires 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 could result in a default under the credit facility, which would permit the participating banks to restrict our ability to access the credit facility and require the immediate repayment of any outstanding advances under the credit facility. As of December 31, 2009, we were in compliance with our debt covenants. The credit facility is with certain commercial lending institutions and is available for general corporate purposes.

Certain lenders that are a party to the 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 credit facility does not restrict the payment of dividends on our common stock, except, if after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby.

Debt Offering On February 27, 2009, we closed an offering of $1 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. The notes are senior unsecured debt and rank *pari passu* with any of our other senior unsecured indebtedness with respect to the payment of both principal and interest.

Obligation Under FPSO Lease On October 6, 2009, we entered into an agreement with an unrelated offshore technology provider for the construction and lease of a floating production, storage and offloading vessel (FPSO) to be used for the development of the Aseng field, offshore Equatorial Guinea. We serve as technical operator of the development project with a 40% working interest.

Construction of the FPSO is scheduled to be completed in 2012, at which time the FPSO will be delivered to Block I, offshore Equatorial Guinea, for the start-up of the Aseng field. The initial term of the lease is for a period of 15 years. We expect to account for the lease agreement as a capital lease. As a result, the FPSO will be included in oil and gas properties and the associated long-term obligation will be included in our balance sheet. We expect that the lease obligation will total approximately $340 million, net to our 40% interest. This amount represents our share of the expected present value of the future minimum lease payments, excluding executory costs, and is subject to change based on change orders implemented during the construction period, final accounting treatment and other factors.

Throughout the construction phase, we will include both the 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.

Monthly lease payments will exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. Annual lease payments, net to our 40% interest, are expected to total approximately $69 million per year for years 1-4 of the lease agreement, $43 million per year for years 5-7; and $8 million per year for the remaining years of the initial 15-year lease term. These payments are also subject to change based on change orders implemented during the construction period and other factors.

Installment Payment Due 2009 On May 11, 2009, we made the final $25 million installment payment to the seller of properties we purchased in 2007. Interest on the unpaid amount was due quarterly and accrued at a LIBOR rate plus .30%. The interest rate was 1.51% at the date of payment.

Debt Repurchases In 2009, we repurchased $5 million of our 7¼% Senior Debentures due August 1, 2097, recognizing a debt extinguishment gain of $1 million. In 2008, we repurchased $11 million of the same notes, recognizing a debt extinguishment gain of $4 million.

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

	As of December 31, 2009
(millions)	
2010	$ -
2011	-
2012	382
2013	-
2014	200
Thereafter	1,434
Total	$ 2,016

Short-Term Borrowings Our credit agreement is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. Other than the installment payments discussed above, no short-term borrowings were outstanding at December 31, 2009 or 2008.

Note 9. Income Taxes

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

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Domestic	$ (808)	$ 1,032	$ 480
Foreign	544	1,029	888
Total	$ (264)	$ 2,061	$ 1,368

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

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Current Taxes			
Federal	$ 45	$ 45	$ 6
State	1	1	1
Foreign	117	306	125
Total Current	163	352	132
Deferred Taxes			
Federal	(320)	363	186
State	(5)	4	6
Foreign	29	(8)	100
Total Deferred	(296)	359	292
Total Income Tax Provision (Benefit)	$ (133)	$ 711	$ 424

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

	Year Ended December 31,		
	2009	2008	2007
(percentages)			
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	11.3	(2.9)	(5.4)
State Taxes, Net of Federal Benefit	1.5	0.2	0.5
Difference Between US and Foreign Rates	(1.4)	1.8	1.6
Percentage Depletion in Excess of Basis	4.5	-	-
Other, Net	(0.5)	0.4	(0.7)
Effective Rate	50.4	34.5	31.0

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2009	2008
(millions)		
Deferred Tax Assets		
Loss Carryforwards	$ 49	$ 36
Ecuador Investment	20	18
Accrued Expenses	17	32
Allowance for Doubtful Accounts	6	20
Net Pension Obligation	34	36
Postretirement Benefits	34	31
Deferred Compensation	73	63
Foreign Tax Credits	28	51
Commodity Derivative Assets	54	-
Other	35	27
Total Deferred Tax Assets	350	314
Valuation Allowance - Foreign Loss Carryforwards	(45)	(35)
Valuation Allowance - Foreign Tax Credits	(28)	(51)
Valuation Allowance - Ecuador Investment	(20)	(18)
Net Deferred Tax Assets	257	210
Deferred Tax Liabilities		
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,302)	(2,388)
Commodity Derivative Assets	-	(138)
Total Deferred Tax Liability	(2,302)	(2,526)
Net Deferred Tax Liability	$ (2,045)	$ (2,316)

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

	December 31,	
	2009	2008
(millions)		
Deferred Income Tax Asset	$ 32	$ -
Deferred Income Tax Liability - Current	(1)	(142)
Deferred Income Tax Liability - Noncurrent	(2,076)	(2,174)
Net Deferred Tax Liability	$ (2,045)	$ (2,316)

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, 2009. 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.

We have recognized deferred tax assets associated with foreign loss carryforwards. The tax effects of these carryforwards totaled $18 million in 2007, increased to $35 million in 2008, and increased to $47 million in 2009. Losses continue to be incurred on our projects in Equatorial Guinea and other new venture activities which are not yet commercial, and we also incurred a small loss in the UK. Therefore, a valuation allowance was provided against $45 million of the deferred tax assets, excluding the UK loss which we expect to utilize in 2010. In 2007, we fully utilized a loss carryforward that arose in the UK in 2006 from accelerated write-offs allowed on our Dumbarton field development. No valuation allowance had been provided against this loss carryforward.

We have recorded a deferred tax asset of $28 million for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations. A valuation allowance of $28 million has been provided against this deferred tax asset.

Our effective tax rate increased to 50% in 2009 as compared with 35% in 2008 and is the result of a tax benefit divided by a pre-tax loss. In the case of a loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate.

Our effective tax rate increased to 35% in 2008 as compared with 31% in 2007 primarily due to the fact that pre-tax earnings increased by a proportionately greater amount than our excludible permanent differences. In addition, there was a rate increase due to (1) a partial shift of taxable income from lower rate jurisdictions such as Equatorial Guinea and Israel to higher rate jurisdictions, (2) the recording of US deferred taxes on the anticipated repatriation of foreign earnings as described below, and (3) the recording of an impairment of a foreign asset on which the tax benefit was offset by a valuation allowance.

During first quarter 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. As of December 31, 2009, the accumulated undistributed earnings of the foreign subsidiaries on which no US taxes have been recorded were approximately $1.2 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 $230 million.

In 2007, China's legislature, the National People's Congress, enacted the China Corporate Income Tax Law. This new legislation decreased our tax rate in China from 33% to 25% starting in 2008, resulting in a $2 million reduction in deferred tax expense.

Adoption of US GAAP for Accounting for Uncertainty in Income Taxes As discussed in Note 2—Significant Accounting Policies, we adopted US GAAP for accounting for uncertainty in income taxes, including unrecognized tax benefits as of January 1, 2007. The adoption had no effect on our financial position or results of operations. 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, 2008 or 2009. 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, 2008 or 2009, 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.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, China – 2006, Israel – 2000, UK – 2007 and the Netherlands – 2005.

Note 10. 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. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to 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 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.

Changes in asset retirement obligations are as follows:

	Year Ended December 31,	
	2009	2008
(in millions)		
Asset Retirement Obligations, Beginning of Period	$ 211	$ 144
Liabilities Incurred in Current Period	22	15
Liabilities Settled in Current Period	(36)	(33)
Revisions	21	75
Accretion Expense	14	10
Asset Retirement Obligations, End of Period	$ 232	$ 211

For the year ended December 31, 2009, liabilities incurred related primarily to properties in the deepwater Gulf of Mexico, the Aseng field in Equatorial Guinea and North Sea projects. Liabilities settled related primarily to properties in the Main Pass and Viosca Knoll areas of the Gulf of Mexico. Revisions relate to the Main Pass asset and a deepwater Gulf of Mexico property.

For the year ended December 31, 2008, liabilities settled related primarily to onshore US and Gulf of Mexico assets. Revisions include $15 million related to our Main Pass asset held for sale at December 31, 2008. The remaining revisions resulted from changes in estimated timing of actual abandonment and overall cost increases for the North Sea assets ($18 million), onshore US and Gulf of Mexico assets ($38 million) and Israel and other locations ($4 million).

Accretion expense is included in depreciation, depletion and amortization expense in the consolidated statements of operations.

Note 11. 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; and
- 28% interest in Alba Plant LLC (Alba Plant), which owns and operates a liquefied petroleum gas processing plant in Equatorial Guinea.

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 investments and is not included in our income tax provision in our consolidated statements of operations. At December 31, 2009, our retained earnings included $123 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment is $24 million higher than the underlying net assets of the investee. $12 million of the difference relates to capitalized interest which is being amortized into earnings over the remaining useful life of the plant. The remaining $12 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,	
	2009	2008
(millions)		
Equity Method Investments		
AMPCO	$ 180	$ 190
Alba Plant	111	106
Other	12	15
Total Equity Method Investments	$ 303	$ 311

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

	December 31,	
	2009	2008
(millions)		
Balance Sheet Information		
Current Assets	$ 269	$ 283
Noncurrent Assets	751	783
Current Liabilities	187	248
Noncurrent Liabilities	59	43

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Statements of Operations Information			
Operating Revenues	$ 632	$ 1,022	$ 934
Operating Expenses	264	301	270
Operating Income	368	721	664
Other Income, Net	(13)	(14)	(14)
Income Before Income Taxes	381	735	678
Income Tax Provision [1]	95	183	44
Net Income	$ 286	$ 552	$ 634

(1) The increase in income tax expense in 2008 is due to the expiration of the Alba Plant tax holiday.

Note 12. Benefit Plans

Pension Plan 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.

We recognize the funded status (the difference between the fair value of plan assets and the 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, 2009 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.

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

	Retirement and Restoration Plans		Medical and Life Plans	
	2009	2008	2009	2008
(millions)				
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 194	$ 188	$ 22	$ 22
Service Cost	12	12	2	2
Interest Cost	11	12	1	1
Benefits Paid	(13)	(17)	(1)	(1)
Plan Amendments [1]	-	-	(2)	-
Actuarial (Gain) Loss	24	(1)	1	(2)
Benefit Obligation at End of Year	228	194	23	22
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	132	155	-	-
Actual Return on Plan Assets	33	(43)	-	-
Employer Contributions	20	37	1	1
Benefits Paid	(13)	(17)	(1)	(1)
Fair Value of Plan Assets at End of Year	172	132	-	-
Funded Status				
Funded Status at End of Year	(56)	(62)	(23)	(22)
Net Amount Recognized in Consolidated Balance Sheets	(56)	(62)	(23)	(22)
Amounts Recognized in Consolidated Balance Sheets Consist of				
Current Liabilities	(2)	(2)	(1)	(1)
Noncurrent Liabilities	(54)	(60)	(22)	(21)
Net Amount Recognized in Consolidated Balance Sheets	(56)	(62)	(23)	(22)
Amounts Not Yet Reflected in Net Periodic Benefit Cost and Included in AOCL				
Prior Service (Cost) Credit	(3)	(3)	7	5
Accumulated Loss	(88)	(86)	(11)	(10)
AOCL	(91)	(89)	(4)	(5)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	35	27	(19)	(17)
Net Amount Recognized in Consolidated Balance Sheets	$ (56)	$ (62)	$ (23)	$ (22)

[1] Plan amendments relate to an increase in the monthly retiree contributions for the medical and life plan.

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

	Retirement and Restoration Plans			Medical and Life Plans		
	Year Ended December 31,			Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
(millions)						
Components of Net Periodic Benefit Cost						
Service Cost	$ 12	$ 12	$ 12	$ 2	$ 2	$ 2
Interest Cost	11	12	10	1	1	1
Expected Return on Plan Assets	(14)	(12)	(11)	-	-	-
Amortization of Prior Service (Credit) Cost	-	-	-	(1)	(1)	(1)
Amortization of Net Loss	3	2	3	1	1	1
Net Periodic Benefit Cost	$ 12	$ 14	$ 14	$ 3	$ 3	$ 3
Other Changes Recognized in AOCL						
Prior Service Cost Arising During Period	$ -	$ -	$ 8	$ (2)	$ -	$ -
Net Loss (Gain) Arising During Period	5	53	(13)	1	(3)	(3)
Amortization of Prior Service Credit	-	-	-	1	1	1
Amortization of Net Loss	(3)	(2)	(3)	(1)	(1)	(1)
Total Recognized in AOCL	$ 2	$ 51	$ (8)	$ (1)	$ (3)	$ (3)
Expected Amortizations for Next Fiscal Year						
Amortization of Prior Service Cost (Credit)	$ -	$ -	$ -	$ (1)	$ (1)	$ (1)
Amortization of Net Loss	5	2	2	1	1	1
Weighted-Average Assumptions Used to Determine Benefit Obligations						
Discount Rate [(1)]	6.00%	6.00% / 6.25%	6.50%	5.50%	6.25%	6.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	-	-	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs						
Discount Rate [(1)]	6.00% / 6.25%	6.50%	5.75%	6.25%	6.25%	5.75%
Expected Long-Term Rate of Return on Plan Assets	8.00%	8.25%	8.25%	-	-	-
Rate of Compensation Increase	5.00%	5.00%	5.00%	-	-	-

(1) The discount rates used to determine benefit obligations at December 31, 2008 and 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,	
	2009	2008
(millions)		
Accumulated Benefit Obligation	$ 197	$ 169
Information for Pension Plans With Projected Benefit Obligations in Excess of Plan Assets		
Projected Benefit Obligation	228	194
Fair Value of Plan Assets	172	132
Information for Pension Plans With Accumulated Benefit Obligations in Excess of Plan Assets		
Accumulated Benefit Obligation	31	169
Fair Value of Plan Assets	-	132

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. We assume the long-term asset mix will be consistent with a target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in the plan's asset allocation. Based on these factors we assumed an average of 8.00% per annum over the life of the plan for the calculation of 2009 net periodic benefit cost. The assumption will be reduced to 7.50% for the calculation of 2010 net periodic benefit cost. No plan assets are expected to be returned to us in 2010.

In order to determine an appropriate discount rate at December 31, 2009, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) 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 $2 million in 2009. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of approximately $2 million in 2009.

Assumed health care cost trend rates were as follows:

	December 31,	
	2009	2008
Health Care Cost Trend Rate Assumed for Next Year	8.00%	8.00%
Rate to Which the Cost Trend Rate is Assumed to Decline (Ultimate Trend Rate)	4.50%	5.00%
Year Rate Reaches Ultimate Trend Rate	2030	2012

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 2009	$ -	$ -
Effect on Year-End 2009 Postretirement Benefit Obligation	3	(2)

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

	Target Allocation	Plan Assets	
	2010	2009	2008
Asset Category			
Equity Securities	70%	73%	65%
Fixed Income	30%	27%	35%
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 the 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 2009.

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, 2010, we had cumulative asset gains (losses) of approximately $(16) million, which remain to be recognized in the calculation of the market-related value of assets.

Additional fair value disclosures about plan assets are as follows:

	Fair Value Measurements at December 31, 2009			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(millions)				
Asset Category				
Federal Money Market Funds	$ 2	$ 2	$ -	$ -
Mutual Funds				
Equity (Common Stocks)	76	76	-	-
Fixed Income	47	47	-	-
Common Collective Trust Funds	47	-	47	-
Total	$ 172	$ 125	$ 47	$ -

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 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.

Contributions As a result of previous contributions made to the pension plan, there are no required contributions expected in 2010. In January 2010, we made a voluntary contribution of $2 million to the pension plan. We may make additional contributions to our pension plan during the year. We expect to make cash contributions of approximately $2 million to the unfunded restoration plan and $1 million to the medical and life plans in 2010. The amounts expected to be contributed to the unfunded restoration and medical and life plans equal expected benefit payments from those plans. (unaudited).

Estimated Future Benefit Payments As of December 31, 2009, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plans	Medical and Life Plans
(millions)		
2010	$ 14	$ 1
2011	18	1
2012	20	1
2013	19	2
2014	21	2
Years 2015 to 2019	120	11

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2009 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 $9 million in 2009, $7 million in 2008, and $6 million in 2007.

Deferred Compensation Plans In connection with the Patina Merger, we acquired the assets and assumed the liabilities related to a Patina shareholder-approved non-qualified deferred compensation plan. This plan was available to officers and certain managers of Patina and allowed participants to defer all or a portion of their salary and annual bonuses (either in cash or common stock). 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,	
	2009	2008
(millions, except share amounts)		
Rabbi Trust Assets		
Mutual Fund Investments	$ 93	$ 71
Noble Energy Common Stock (at Fair Value) (1)	75	52
Total Rabbi Trust Assets	168	123
Liability Under Patina Deferred Compensation Plan	$ 168	$ 123
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	1,049,140	1,051,032

(1) Shares of our common stock are accounted for as treasury stock and recorded at cost in the consolidated balance sheets.

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 5. 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) 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 one million shares, or 95%, of our common stock held in the plan at December 31, 2009 were attributable to a member of our Board of Directors. Plan participants sold 1,892 shares of our common stock in 2009, 50,000 shares in 2008, and no shares in 2007. Proceeds were invested in mutual funds. Distributions to plan participants totaled $1 million in 2008 and $2 million in 2007. Distributions to plan participants 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 $23 million in 2009, deferred compensation income of $32 million in 2008, and deferred compensation expense of $33 million in 2007.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. Deferred compensation liabilities of $45 million and $36 million were outstanding at December 31, 2009 and 2008, respectively, under the unfunded plan.

Note 13. Stock-Based Compensation

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 36	$ 38	$ 25
Exploration Expense and Other	13	1	2
Total Stock-Based Compensation Expense	$ 49	$ 39	$ 27
Tax Benefit Recognized	$ (17)	$ (15)	$ (10)

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. In 2007, our stockholders approved an amendment to the 1992 Plan that increased the maximum number of shares of our common stock that may be issued from 18 million to 22 million shares. In 2009, our stockholders approved an amendment to the 1992 Plan that increased the maximum number of shares of our common stock that may be issued from 22 million to 24 million shares. At December 31, 2009, 12,263,457 shares of our common stock were reserved for issuance, including 4,706,057 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. Restricted stock awards generally vest over three years. In 2009, we began making grants of restricted stock under the 1992 Plan that 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. These awards are accounted for in accordance with US GAAP for stock-based compensation, which provides for the grant-date fair value of the awards to be recognized in the statement of operations over the service period. Our cash based performance units, which were issued in 2006 and vested in 2009, were accounted for in accordance with US GAAP for contingencies.

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, 2009, 730,349 shares of our common stock were reserved for issuance, including 568,841 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.

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.

Patina Stock Option Plans Patina maintained a shareholder approved stock option plan for employees (the Patina Employee Plan) that provided for the issuance of options at prices not less than fair value at the date of grant. Patina also maintained a shareholder approved stock grant and option plan for non-employee directors (the Patina Directors' Plan). The Patina Directors' Plan provided for stock options to be granted to each non-employee director upon appointment and upon annual re-election thereafter. Upon completion of the Patina Merger, all unvested stock options outstanding under the Patina Employee Plan and the Patina Directors' Plan became fully vested, and all outstanding options were converted into options to purchase our common stock. The remaining Patina options expire in 2010.

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 to arrive at an approximated 5.5-year risk free rate of return.
- *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 were as follows:

	Year Ended December 31,		
	2009	2008	2007
(weighted averages)			
Expected Term (in Years)	5.5	5.5	5.5
Expected Volatility	43.0%	27.7%	29.6%
Risk-Free Rate	2.0%	2.9%	4.7%
Expected Dividend Yield	1.2%	1.0%	0.6%

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, 2008	6,082,375	$ 41.41		
Granted	1,574,252	50.99		
Exercised	(704,209)	25.01		
Forfeited	(132,127)	56.90		
Outstanding at December 31, 2009	6,820,291	$ 45.01	6.0	$ 182
Exercisable at December 31, 2009	4,245,616	$ 37.62	4.4	$ 144

The weighted-average grant-date fair value of options granted was $19.14 in 2009, $20.40 in 2008, and $18.77 in 2007. The total intrinsic value of options exercised was $19 million in 2009, $67 million in 2008, and $68 million in 2007.

As of December 31, 2009, $29 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.4 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards Restricted stock activity was as follows:

	Shares Subject to Service Conditions	Weighted Average Grant Date Fair Value	Shares Subject to Market Conditions	Weighted Average Grant Date Fair Value
		(per share)		*(per share)*
Outstanding at December 31, 2008	891,027	$ 62.91	68,493	$ 35.40
Awarded	612,226	51.63	-	-
Vested	(19,245)	64.47	(68,493)	35.40
Forfeited	(62,808)	58.18	-	-
Outstanding at December 31, 2009	1,421,200	$ 58.31	-	$ -

The total fair value of restricted stock that vested was $4 million in 2009, $10 million in 2008, and $6 million in 2007.

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.

In 2006, we awarded restricted stock with market-based vesting criteria. The fair value of the market-based restricted stock awards was estimated on the date of award using a Monte Carlo valuation model that used an expected volatility assumption of 28.4% and a risk free rate assumption of 4.4%. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. The number of simulations used was 100,000. Expected volatility represents the extent to which our stock price is expected to fluctuate between the award date and the award's anticipated term. We used the historical volatility of our common stock for the three-year period ended prior to the date of award. The risk-free rate was based on a three-year period from US Treasury securities as of the year ended prior to the date of award. These awards vested in 2009.

As of December 31, 2009, $33 million of compensation cost related to all of our unvested restricted stock awarded under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.4 years. Common stock dividends accrue on restricted stock grants and are paid upon vesting. We issue new shares of our common stock when awarding restricted stock.

Note 14. Earnings Per Share

Basic earnings per share of our common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of our common stock may include the effect of our shares held in a rabbi trust, outstanding stock options or shares of restricted stock, except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings per share:

	Year Ended December 31, 2009	2008	2007
(millions, except per share amounts)			
Net Income (Loss)	$ (131)	$ 1,350	$ 944
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	-	(20)	-
Net Income (Loss) Used for Diluted Earnings Per Share Calculation	$ (131)	$ 1,330	$ 944
Weighted Average Number of Shares Outstanding, Basic	173	173	171
Incremental Shares from Assumed Conversion of Dilutive Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	-	3	2
Weighted Average Number of Shares Outstanding, Diluted	173	176	173
Earnings (Loss) Per Share, Basic	**$ (0.75)**	**$ 7.83**	**$ 5.52**
Earnings (Loss) Per Share, Diluted	**(0.75)**	**7.58**	**5.45**

(1) The diluted earnings per share calculation for 2008 includes a decrease to net income of $20 million (net of tax) related to a deferred compensation gain from shares of our common stock held in a rabbi trust. When dilutive, the deferred compensation gain or loss (net of tax) is excluded from net income while the shares of our common stock held in the rabbi trust are included in the outstanding diluted share count.

The effect of stock options and unvested shares of restricted stock outstanding has not been included in the calculation of weighted average shares outstanding for diluted earnings per share for the year ended December 31, 2009 as their effect would have been antidilutive. Had we recognized net income for this period, incremental shares attributable to the assumed exercise of outstanding options and shares of restricted stock would have increased diluted weighted average shares outstanding by 2 million shares for the year ended December 31, 2009.

A total of 3.7 million, 1.2 million, and 2.1 million weighted average stock options, shares of restricted stock and shares of our common stock held in a rabbi trust were antidilutive for the years ended December 31, 2009, 2008 and 2007, respectively, and were excluded from the calculation of diluted earnings per share. The weighted average exercise prices of the antidilutive stock options were $60.40 per share, $67.64 per share, and $52.41 per share for the years ended December 31, 2009, 2008 and 2007, respectively.

Note 15. 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 and Cameroon); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International, Corporate and Marketing. Other International includes China, Ecuador and Argentina (through February 2008) operations and the gain on sale of Argentina (in 2009).

Accounting policies for geographical segments are the same as those described in the summary of significant accounting policies. 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.

Noble Energy, Inc.
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(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l, Corporate, Marketing
Year Ended December 31, 2009						
Revenues from Third Parties	$ 2,287	$ 1,323	$ 340	$ 144	$ 153	$ 327
Reclassification from AOCL [1]	(58)	(29)	(29)	-	-	-
Intersegment Revenue	-	161	-	-	-	(161)
Income from Equity Method Investees	84	-	84	-	-	-
Total Revenues [2]	2,313	1,455	395	144	153	166
DD&A	816	689	38	20	34	35
Asset Impairments	604	504	-	-	-	100
Loss 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
Total Assets at December 31, 2009 [3]	11,807	8,669	1,731	486	635	286
Year Ended December 31, 2008						
Revenues from Third Parties	$ 4,058	$ 2,315	$ 541	$ 157	$ 410	$ 635
Reclassification from AOCL [1]	(331)	(290)	(41)	-	-	-
Intersegment Revenue	-	434	-	-	-	(434)
Income from Equity Method Investees	174	-	174	-	-	-
Total Revenues [2]	3,901	2,459	674	157	410	201
DD&A	791	646	34	24	55	32
Asset Impairments	294	224	-	-	-	70
Gain on Commodity Derivative Instruments	(440)	(363)	(77)	-	-	-
Income (Loss) Before Income Taxes	2,061	1,333	689	122	284	(367)
Equity Method Investments	$ 311	$ -	$ 311	$ -	$ -	$ -
Additions to Long-Lived Assets	2,179	1,842	143	39	94	61
Total Assets at December 31, 2008 [3]	12,384	9,212	1,614	366	775	417
Year Ended December 31, 2007						
Revenues from Third Parties	$ 3,115	$ 1,651	$ 418	$ 113	$ 364	$ 569
Reclassification from AOCL [1]	(54)	(42)	(12)	-	-	-
Intersegment Revenue	-	343	-	-	-	(343)
Income from Equity Method Investees	211	-	211	-	-	-
Total Revenues [2]	3,272	1,952	617	113	364	226
DD&A	736	580	25	18	81	32
Loss on Involuntary Conversion of Assets	51	51	-	-	-	-
Income (Loss) Before Income Taxes	1,368	810	517	86	221	(266)
Equity Method Investments	$ 357	$ -	$ 357	$ -	$ -	$ -
Additions to Long-Lived Assets	1,623	1,285	151	26	83	78
Total Assets at December 31, 2007 [3]	10,831	7,918	1,355	268	562	728

(1) Revenues 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.

(2) Revenues from third parties for all foreign countries, in total, were $791 million in 2009, $1.3 billion in 2008, and $1.1 billion in 2007.

(3) The US reporting unit includes goodwill of $758 million at December 31, 2009, $759 million at December 31, 2008, and $761 million at December 31, 2007. Long-lived assets located in all foreign countries, in total, were $1.6 billion, $1.5 billion, and $1.4 billion at December 31, 2009, 2008, and 2007, respectively.

Note 16. Additional Shareholders' Equity Information

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

	Year Ended December 31,	
	2009	2008
Common Stock Shares Issued		
Shares, Beginning of Period	192,296,764	190,814,309
Exercise of Common Stock Options	704,209	1,080,116
Restricted Stock Awards, Net of Forfeitures	549,418	402,339
Shares, End of Period	193,550,391	192,296,764
Treasury Stock		
Shares, Beginning of Period	18,563,409	18,580,865
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	20,784	32,544
Rabbi Trust Shares Sold	(1,892)	(50,000)
Shares, End of Period	18,582,301	18,563,409

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

	Accumulated Other Comprehensive Loss		
	Oil and Gas Cash Flow Hedges	Pension-Related and Other	Total
(millions)			
December 31, 2006			
Cash Flow Hedges	$ (104)	$ (36)	$ (140)
Realized Amounts Reclassified Into Earnings	33	3	36
Unrealized Change in Fair Value	(184)	(1)	(185)
Net Change in Other	-	5	5
December 31, 2007	(255)	(29)	(284)
Cash Flow Hedges			
Realized Amounts Reclassified Into Earnings	207	3	210
Unrealized Change in Fair Value	-	(4)	(4)
Net Change in Other	-	(32)	(32)
December 31, 2008	(48)	(62)	(110)
Cash Flow Hedges			
Realized Amounts Reclassified Into Earnings	36	3	39
Net Change in Other	-	(4)	(4)
December 31, 2009	$ (12)	$ (63)	$ (75)

All amounts in the table above are reported net of tax. The effective income tax rate applied to AOCL was 37.6% for the period December 31, 2006 - 2008, and 35.0% at December 31, 2009.

Note 17. Commitments and Contingencies

Purchaser Bankruptcy We had an exposure from crude oil sales for the months of June and July 2008 to SemCrude, L.P. (SemCrude), a subsidiary of SemGroup, L.P. (SemGroup). On July 22, 2008, SemGroup, including SemCrude, filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code under Case Number 08-11525 (BLS) in the United States Bankruptcy Court for the District of Delaware. During 2008, we determined that the carrying value of our receivable of $71 million should be reduced by $38 million. Based upon the confirmation of SemCrude's plan for reorganization on October 26, 2009, and further based upon a settlement reached with SemCrude on October 27, 2009, we further reduced the carrying value of our receivable by $12 million. We have received distributions of approximately $12 million from SemCrude and believe the disposition of this matter to be finally determined.

Legal Proceedings We are involved in various other 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.

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 approximately $22 million in 2009, $20 million in 2008, and $13 million in 2007.

Noble Energy, Inc.
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Minimum commitments as of December 31, 2009 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Throughput Agreement	Transportation and Gathering	Operating Lease Obligations	FPSO Lease Obligation [1]	Total
2010	$ 671	$ 19	$ 11	$ 12	$ -	$ 713
2011	336	19	10	10	-	375
2012	27	19	7	9	35	97
2013	-	19	6	10	69	104
2014	-	5	3	11	69	88
2015 and Thereafter	-	-	3	31	295	329
Total	$ 1,034	$ 81	$ 40	$ 83	$ 468	$ 1,706

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. These payments are also subject to change based on change orders implemented during the construction period, final accounting treatment and other factors. See Note 8. Debt.

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 reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve 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.

Recent SEC and FASB Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. See Note 2. Summary of Significant Accounting Policies – Recently Adopted Standards. We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserves estimates.

In addition, in January 2010 the FASB issued Accounting Standards Update 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the SEC rules. See Note 2. Summary of Significant Accounting Policies – Recently Adopted Standards.

Application of the new 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 new rules resulted in a decrease in proved reserves of approximately 27 MMBoe. Use of year-end prices as required by the old 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 Wattenberg field, 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 new standards had an impact on fourth quarter 2009 DD&A expense. We estimate the impact of using 12-month average commodity prices, as required by the new 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, Denver and London 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 reserves engineers, to perform a reserves audit of proved reserves as of December 31, 2009. The reserves audit included a detailed review of 20 of our major international, deepwater Gulf of Mexico and US onshore fields, which covered approximately 78% of US proved reserves and 96% of international proved reserves (86% of total proved reserves). For additional information regarding reserves audits for the years 2009, 2008, and 2007, 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, North Sea, China, and Argentina (through February 2008). Operations in Equatorial Guinea, Ecuador, China, Cyprus and Suriname are conducted in accordance with the terms of production sharing contracts. Operations in Cameroon are conducted in accordance with the terms of a production sharing contract and a mining concession. Operations in other foreign locations are conducted in accordance with concession agreements or licenses.

Definitions The following definitions apply to the terms used in the paragraphs above:

Reserves Estimate The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Reserves Audit The process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

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

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 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).

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

Proved Oil Reserves (Unaudited) The following reserves schedule was developed by our reserves 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, 2006	170	90	36	296
Revisions of Previous Estimates [2]	28	-	1	29
Extensions, Discoveries and Other Additions [3]	27	-	10	37
Purchase of Minerals in Place	-	-	-	-
Sale of Minerals in Place	(2)	-	-	(2)
Production [4]	(16)	(8)	(7)	(31)
December 31, 2007	207	82	40	329
Revisions of Previous Estimates [2]	(10)	1	-	(9)
Extensions, Discoveries and Other Additions [3]	16	-	11	27
Purchase of Minerals in Place	3	-	-	3
Sale of Minerals in Place [5]	-	-	(7)	(7)
Production [4]	(18)	(8)	(6)	(32)
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	1	-	-	1
Sale of Minerals in Place	-	-	-	-
Production [4]	(17)	(8)	(4)	(29)
December 31, 2009	209	92	35	336
Proved Developed Reserves as of:				
December 31, 2006	115	90	35	240
December 31, 2007	129	71	29	229
December 31, 2008	121	57	21	199
December 31, 2009	122	49	23	194
Proved Undeveloped Reserves as of:				
December 31, 2006	55	-	1	56
December 31, 2007	78	11	11	100
December 31, 2008	77	18	17	112
December 31, 2009	87	43	12	142

(1) Other International includes the North Sea, China and Argentina. We sold our Argentina assets in February 2008.

(2) The 2007 positive revisions within the US are primarily due to 29 MMBbl of NGLs, previously recorded in proved natural gas reserves, being reflected in proved oil reserves, partially offset by negative revisions within the US Southern region related to less than expected well performance. The 2008 negative revisions within the US are primarily due to lower year-end prices (28 MMBbl), partially offset by the recording of NGLs which had previously been recorded in proved natural gas reserves. 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 proved undeveloped reserves 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).

(3) The 2007 increase in proved reserves includes 17 MMBbl in the US Wattenberg field, primarily due to infill drilling activities, 8 MMBbl in the deepwater Gulf of Mexico and 10 MMBbl in the North Sea Dumbarton field area. The 2008 increase in proved reserves includes 13 MMBbl in the US Wattenberg field, primarily due to infill drilling activities, and 9 MMBbl in China. The 2009 increase in proved reserves includes 20 MMBbl related to the ongoing development of the US Wattenberg field, 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.

(4) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2009, 3 MMBbl in 2008, and 3 MMBbl in 2007.

(5) The decrease is due to sale of our Argentina assets. See Note 4. Acquisitions and Divestitures.

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

Proved Gas Reserves (Unaudited) The following reserves schedule was developed by our reserves 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, 2006	1,739	945	360	187	3,231
Revisions of Previous Estimates [(2)]	(67)	44	-	28	5
Extensions, Discoveries and Other Additions [(3)]	316	-	-	3	319
Purchase of Minerals in Place	3	-	-	-	3
Sale of Minerals in Place	-	-	-	-	-
Production	(151)	(48)	(41)	(11)	(251)
December 31, 2007	1,840	941	319	207	3,307
Revisions of Previous Estimates [(2)]	(253)	34	1	8	(210)
Extensions, Discoveries and Other Additions [(3)]	345	78	4	-	427
Purchase of Minerals in Place [(4)]	72	-	-	-	72
Sale of Minerals in Place	-	-	-	-	-
Production	(145)	(75)	(51)	(10)	(281)
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	6	-	-	-	6
Sale of Minerals in Place	-	-	-	-	-
Production	(145)	(87)	(42)	(11)	(285)
December 31, 2009	1,534	940	234	196	2,904
Proved Developed Reserves as of:					
December 31, 2006	1,255	360	303	187	2,105
December 31, 2007	1,259	830	263	204	2,556
December 31, 2008	1,268	700	216	201	2,385
December 31, 2009	1,114	638	191	192	2,135
Proved Undeveloped Reserves as of:					
December 31, 2006	484	585	57	-	1,126
December 31, 2007	581	111	56	3	751
December 31, 2008	591	278	57	4	930
December 31, 2009	420	302	43	4	769

(1) Other International includes the North Sea, Ecuador and China. See Note 3. Impairments for a discussion of impairment charges related to our investment in Ecuador.

(2) The 2007 negative revisions within the US are primarily due to 103 Bcf of natural gas being reflected in the proved oil reserves table as NGLs, partially offset by positive revisions resulting from an increase in commodity price. The 2008 negative revisions in the US are primarily due to lower year-end prices (109 Bcf), as well as additional natural gas volumes being reflected in the proved oil reserves table as NGLs. The 2009 negative revisions in the US are primarily due to lower year-end prices (224 Bcf), reclassifications of proved undeveloped reserves 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). Equatorial Guinea's positive revisions in 2007, 2008 and 2009 are primarily due to additional production allowances related to LNG sales. The 2007 positive revisions in Ecuador are related to better than expected well performance.

(3) The 2007 increase in US proved reserves includes 142 Bcf in the Wattenberg field, 83 Bcf in the Piceance basin and 19 Bcf in the Niobrara trend, primarily due to infill drilling activities. The 2008 increase in US proved reserves includes 106 Bcf in the Wattenberg field and 173 Bcf in the Rocky Mountain area, primarily in the Piceance basin and Niobrara trend, primarily due to infill drilling activities. The remaining increase is due to other development programs in the US Northern and Southern regions. The 2009 increase in US proved reserves is primarily due to ongoing low-risk development programs onshore in the Wattenberg field, the Rocky Mountain area, and East Texas.

(4) Purchase of minerals in place is primarily due to the Mid-continent acquisition. See Note 4. Acquisitions and Divestitures.

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

Results of Operations for Oil and Gas Producing Activities (Unaudited) Aggregate results of operations in connection with 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, 2009					
Revenues					
Sales [2]	$ 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 [3]	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 [4]	$ (236)	$ 192	$ 80	$ 11	$ 47
Year Ended December 31, 2008					
Revenues					
Sales [2]	$ 2,459	$ 500	$ 157	$ 535	$ 3,651
Sales to Affiliated Power Plant	-	-	-	30	30
Total Revenues	2,459	500	157	565	3,681
Production Costs [3]	470	42	12	123	647
Exploration Expense	111	7	4	60	182
DD&A	653	34	23	75	785
Asset Impairments	224	-	-	-	224
Income before Income Taxes	1,001	417	118	307	1,843
Income Tax Expense	339	99	22	151	611
Results of Operations [4]	$ 662	$ 318	$ 96	$ 156	$ 1,232
Year Ended December 31, 2007					
Revenues					
Sales [2]	$ 1,952	$ 406	$ 113	$ 495	$ 2,966
Sales to Affiliated Power Plant	-	-	-	35	35
Total Revenues	1,952	406	113	530	3,001
Production Costs [3]	390	42	10	107	549
Exploration Expense	122	26	1	38	187
DD&A	595	25	18	112	750
Asset Impairments	4	-	-	-	4
Income before Income Taxes	841	313	84	273	1,511
Income Tax Expense	191	84	14	128	417
Results of Operations [4]	$ 650	$ 229	$ 70	$ 145	1,094

(1) Other International includes the North Sea, Ecuador, China, Cameroon, Cyprus, Argentina (through February 2008) and other new ventures.

(2) Includes impact resulting from applying cash flow hedge accounting for related commodity derivative instruments. See Note 6. Derivative Instruments and Hedging Activities.

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

(4) Results of operations from oil and gas producing activities exclude the mark-to-market gain or loss on commodity derivative instruments, corporate overhead and interest costs. See Note 6. Derivative Instruments and Hedging Activities.

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

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) [1]
Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [2]	Total
(millions)					
Year Ended December 31, 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
Year Ended December 31, 2008					
Property Acquisition Costs					
Proved [3]	$ 256	$ -	$ -	$ -	$ 256
Unproved [4]	296	-	-	6	302
Total Acquisition Costs	552	-	-	6	558
Exploration Costs [5]	322	105	28	62	517
Development Costs [6]	1,106	38	13	108	1,265
Total Consolidated Operations	$ 1,980	$ 143	$ 41	$ 176	$ 2,340
Year Ended December 31, 2007					
Property Acquisition Costs					
Proved	$ 11	$ -	$ -	$ -	$ 11
Unproved	145	-	-	1	146
Total Acquisition Costs	156	-	-	1	157
Exploration Costs	184	131	2	103	420
Development Costs [6]	1,081	15	25	70	1,191
Total Consolidated Operations	$ 1,421	$ 146	$ 27	$ 174	$ 1,768

(1) Costs incurred include capitalized and expensed items.
(2) Other International includes the North Sea, Ecuador, China, Cameroon, Cyprus, Argentina (through February 2008) and other new ventures.
(3) 2009 proved property acquisition costs include a $6 million downward purchase price adjustment related to the Mid-continent acquisition. 2008 proved property acquisition costs include $254 million related to the Mid-continent acquisition.
(4) 2009 unproved property acquisition costs include $56 million for deepwater Gulf of Mexico lease blocks and the remainder primarily for other onshore US lease acquisitions. 2008 unproved property acquisition costs include $179 million for deepwater Gulf of Mexico lease blocks, $38 million related to the Mid-continent acquisition, $39 million related to lease acquisitions in East Texas and the remainder primarily for other onshore US lease acquisitions.
(5) 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. 2008 exploration costs include drilling and completion costs of $72 million in deepwater Gulf of Mexico, $98 million in Equatorial Guinea and $25 million in Israel.
(6) Worldwide development costs include amounts spent to develop proved undeveloped reserves of approximately $440 million in 2009, $528 million in 2008 and $390 million in 2007. Equatorial Guinea development costs for 2009 include a non-cash accrual of $29 million related to estimated construction progress to date on an FSPO to be used in the development of the Aseng field in Equatorial Guinea. These capitalized costs will be included in development costs as the FPSO is constructed. US development costs include increases in asset retirement obligations of $11 million in 2009, $34 million in 2008 and $24 million in 2007. Other international development costs include increases in asset retirement obligations of $5 million in 2009, $18 million in 2008 and $9 million in 2007.

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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, including asset retirement costs and related accumulated DD&A, are as follows:

	December 31, 2009	December 31, 2008
(millions)		
Unproved Oil and Gas Properties [1]	$ 874	$ 961
Proved Oil and Gas Properties [2]	11,710	11,002
Total Oil and Gas Properties	12,584	11,963
Accumulated DD&A	(3,809)	(3,054)
Net Capitalized Costs	$ 8,775	$ 8,909

(1) Unproved oil and gas properties includes $263 million and $465 million at December 31, 2009 and 2008, respectively, remaining from the allocation of costs to unproved properties acquired in the Patina Merger and the acquisition of U.S. Exploration.

(2) Proved oil and gas properties include asset retirement costs of $176 million and $180 million at December 31, 2009 and 2008, respectively.

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

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited) The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows in accordance with US GAAP for extractive activities. The standards require the use of a 10% discount rate. This information is not the fair value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves.

(millions)	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
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
December 31, 2008					
Future Cash Inflows [2]	$ 16,551	$ 3,277	$ 938	$ 2,299	$ 23,065
Future Production Costs [3]	4,646	784	120	876	6,426
Future Development Costs	3,082	62	160	349	3,653
Future Income Tax Expense	2,594	774	173	473	4,014
Future Net Cash Flows	6,229	1,657	485	601	8,972
10% Annual Discount for Estimated Timing of Cash Flows	3,180	608	106	214	4,108
Standardized Measure of Discounted Future Net Cash Flows	$ 3,049	$ 1,049	$ 379	$ 387	$ 4,864
December 31, 2007					
Future Cash Inflows [2]	$ 30,733	$ 6,935	$ 858	$ 4,075	$ 42,601
Future Production Costs [3]	5,936	1,112	180	1,025	8,253
Future Development Costs	3,136	202	88	227	3,653
Future Income Tax Expense	6,622	1,348	146	1,121	9,237
Future Net Cash Flows	15,039	4,273	444	1,702	21,458
10% Annual Discount for Estimated Timing of Cash Flows	7,398	1,705	163	541	9,807
Standardized Measure of Discounted Future Net Cash Flows	$ 7,641	$ 2,568	$ 281	$ 1,161	$ 11,651

(1) Other International includes the North Sea, Ecuador, China and Argentina. We sold our Argentina assets in February 2008.

(2) The standardized measure of discounted future net cash flows for 2009, 2008 and 2007 does not include cash flows relating to anticipated future methanol or electricity 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.

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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, 2009 [2]					
Average Crude Oil 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
December 31, 2008					
Average Crude Oil Price per Bbl	$ 36.62	$ 40.51	$ -	$ 40.05	$ 37.97
Average Natural Gas Price per Mcf	4.99	0.25	3.43	3.82	3.39
December 31, 2007					
Average Crude Oil Price per Bbl	$ 88.00	$ 81.26	$ -	$ 82.20	$ 85.62
Average Natural Gas Price per Mcf	6.78	0.27	2.69	4.04	4.36

(1) Other International includes the North Sea, Ecuador, and China at December 31, 2009, 2008 and 2007 and also includes Argentina at December 31, 2007.

(2) The new SEC and FASB reserves reporting rules require the use of 12-month average commodity prices instead of year-end commodity prices.

We estimate that a $1.00 per Bbl change in the average price of crude oil or a $.10 per Mcf change in the average price of natural gas from the 12-month average prices for 2009 would change the discounted future net cash flows before income taxes by approximately $188 million or $150 million, respectively.

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 proved undeveloped reserves of $900 million in 2010, $800 million in 2011 and $500 million in 2012.

Future income tax expense is computed by applying the appropriate year-end statutory tax rates to the estimated future pretax 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,		
	2009	2008	2007
(millions)			
Imbalance receivables	$ 21	$ 7	$ 13
Imbalance liabilities	12	8	10

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

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Supplemental Oil and Gas Information
(Unaudited)

Sources of Changes in Discounted Future Net Cash Flows (Unaudited) Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are as follows:

	Year Ended December 31,		
	2009	2008	2007
(millions)			
Standardized Measure of Discounted Future Net Cash Flow s, Beginning of Year	$ 4,864	$ 11,651	$ 6,887
Changes in Standardized Measure of Discounted Future Net Cash Flow s			
Sales of Oil and Gas Produced, Net of Production Costs	(1,528)	(3,030)	(2,427)
Net Changes in Prices and Production Costs	(878)	(8,017)	5,266
Extensions, Discoveries and Improved Recovery, Less Related Costs	815	400	1,635
Changes in Estimated Future Development Costs	(132)	(883)	(775)
Development Costs Incurred During the Period	971	1,291	1,189
Revisions of Previous Quantity Estimates	436	(617)	1,276
Purchases of Minerals in Place	5	182	6
Sales of Minerals in Place	-	(66)	(95)
Accretion of Discount	707	1,663	1,006
Net Change in Income Taxes	(75)	2,853	(1,900)
Change in Timing of Estimated Future Production and Other	(253)	(563)	(417)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flow	68	(6,787)	4,764
Standardized Measure of Discounted Future Net Cash Flow s, End of Year	$ 4,932	$ 4,864	$ 11,651

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)					
2009 [1]					
Revenues	$ 441	$ 491	$ 621	$ 760	$ 2,313
Income (Loss) Before Income Taxes	(374)	(90)	115	85	(264)
Net Income (Loss)	(188)	(57)	107	8	(131)
Earnings (Loss) Per Share					
Basic [3]	$ (1.09)	$ (0.33)	$ 0.62	$ 0.05	$ (0.75)
Diluted [3]	(1.09)	(0.33)	0.61	0.05	$ (0.75)
2008 [2]					
Revenues	$ 1,025	$ 1,205	$ 1,098	$ 573	$ 3,901
Income (Loss) Before Income Taxes	315	(198)	1,454	490	2,061
Net Income (Loss)	215	(144)	974	305	1,350
Earnings (Loss) Per Share					
Basic [3]	$ 1.25	$ (0.84)	$ 5.64	$ 1.77	$ 7.83
Diluted [3] [4]	1.20	(0.84)	5.37	1.72	7.58

(1) First quarter 2009 included the following:
- $73 million gain on commodity derivative instruments. (See Note 6. Derivative Instruments and Hedging Activities);
- $437 million asset impairment charges (See Note 3. Asset Impairments); and
- $46 million reversal of Ecuador allowance for doubtful accounts (See Note 2. Summary of Significant Accounting Policies).

Second quarter 2009 included the following:
- $139 million loss on commodity derivative instruments. (See Note 6. Derivative Instruments and Hedging Activities); and
- $24 million gain on sale of interest in Argentina, which had been deferred until government approval of the sale.

Third quarter 2009 included the following:
- $28 million loss on commodity derivative instruments (See Note 6. Derivative Instruments and Hedging Activities); and
- $12 million write-down of SemCrude, L.P. receivable (See Note 17. Commitments and Contingencies).

Fourth quarter 2009 included the following:
- $16 million loss on commodity derivative instruments (See Note 6. Derivative Instruments and Hedging Activities);
- $167 million asset impairment charges (See Note 3. Asset Impairments); and
- $97 million refund of deepwater Gulf of Mexico royalties, including interest (See Note 2. Summary of Significant Accounting Policies).

(2) First quarter 2008 included the following:
- $237 million loss on commodity derivative instruments. (See Note 6. Derivative Instruments and Hedging Activities).

Second quarter 2008 included the following:
- $828 million loss on commodity derivative instruments. (See Note 6. Derivative Instruments and Hedging Activities).

Third quarter 2008 included the following:
- $875 million gain on commodity derivative instruments (See Note 6. Derivative Instruments and Hedging Activities);
- $38 million write-down of SemCrude, L.P. receivable (See Note 17. Commitments and Contingencies); and
- $38 million asset impairment charges (See Note 3. Asset Impairments).

Fourth quarter 2008 included the following:
- $630 million gain on commodity derivative instruments (See Note 6. Derivative Instruments and Hedging Activities); and
- $256 million asset impairment charges (See Note 3. 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) The diluted earnings per share calculations for the quarters ended September 30, 2008 and December 31, 2008 include decreases to net income of $29 million, net of tax, and $4 million, net of tax, respectively, related to deferred compensation gains related to shares of our common stock held in a rabbi trust.

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 accounting principles generally accepted in the United States.

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, 2009. Based on our assessment, our internal controls over financial reporting were effective. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2009.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2009.

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 2010 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2009.

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

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2009.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2009.

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.

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 18, 2010	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, Chief Executive Officer and Director
Date: February 18, 2010	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Senior Vice President, Chief Financial Officer
Date: February 18, 2010	By: /s/ Frederick B. Bruning Frederick B. Bruning, Vice President, Chief Accounting Officer

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 18, 2010
/s/ Kenneth M. Fisher Kenneth M. Fisher	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 18, 2010
/s/ Frederick B. Bruning Frederick B. Bruning	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 18, 2010
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 18, 2010
/s/ Michael A. Cawley Michael A. Cawley	Director	February 18, 2010
/s/ Edward F. Cox Edward F. Cox	Director	February 18, 2010
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 18, 2010
/s/ Eric P. Grubman Eric P. Grubman	Director	February 18, 2010
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 18, 2010
/s/ Scott D. Urban Scott D. Urban	Director	February 18, 2010
/s/ William T. Van Kleef William T. Van Kleef	Director	February 18, 2010

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
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).
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*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.5*	—	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.6*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.7*	—	Letter agreement dated February 1, 2002 between the Registrant and Charles D. Davidson, terminating Mr. Davidson's employment agreement and entering into the attached Change of Control Agreement (filed as Exhibit 10.17 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.8	—	$2.1 billion Five-Year Credit Agreement, dated November 30, 2006, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Wachovia Bank, National Association and The Royal Bank of Scotland PLC, as co-syndication agents, Deutsche Bank Securities Inc., Citibank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as co-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: November 30, 2006), filed December 6, 2006 and incorporated herein by reference).
10.9*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009, (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
10.10*	—	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).
10.11*	—	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).
10.12*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (effective September 1, 2008) (filed as Exhibit to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 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 herewith.
10.15*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 28, 2009), (filed as exhibit 10.1 to Registrant's Current Report on Form 8-K (Date of Event: April 28, 2009) filed April 29, 2009 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*	—	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*	—	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).
10.19*	—	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2009), (filed as Exhibit 10.31 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Registered Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
23.3	—	Consent of Independent Petroleum Engineers and Geologists—Netherland, Sewell & Associates, Inc., filed herewith.

Exhibit Number		Exhibit **
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 Independent Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
99.2	—	Report of Netherland, Sewell & Associates, Inc., filed herewith.
101	—	The following materials from the Noble Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Shareholders' Equity, (v) Consolidated Statements of Comprehensive Income and (vi) Notes to the Consolidated Financial Statements, tagged as blocks of text.

* 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.

GLOSSARY

In this report, the following abbreviations are used:

Bbl(s)	Barrel(s)
MBbls	Thousand barrels
MMBbls	Million barrels
Bpd	Barrels per day
MBpd	Thousand barrels per day
Bopd	Barrels oil per day
MBopd	Thousand barrels per day
Boe	Barrels oil equivalent; gas is converted on the basis of six Mcf of gas per one barrel of oil, condensate or natural gas liquids
MBoe	Thousand barrels oil equivalent
MMBoe	Million barrels oil equivalent
Boepd	Barrels oil equivalent per day
MBoepd	Thousand barrels oil equivalent per day
MMgal	Million gallons
KWh	Kilowatt hours
MW	Megawatt
GW	Gigawatt
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
MMcfpd	Million cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcfe	Million cubic feet equivalent
Bcfe	Billion cubic feet equivalent
Tcfe	Trillion cubic feet equivalent
Btu	British thermal unit
MMBtu	Million British thermal units
MMBtupd	Million British thermal units per day
MTpd	Metric tons per day
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural gas liquid

DIRECTORS

Charles D. Davidson (4)	*Chairman of the Board and Chief Executive Officer, Noble Energy, Inc.*
Jeffery L. Berenson (2) (3)	*President and Chief Executive Officer, Berenson & Company*
Michael A. Cawley (1) (3)	*Trustee, President and Chief Executive Officer, The Samuel Roberts Noble Foundation, Inc.*
Edward F. Cox (2) (3) (4)	*Retired Partner, law firm of Patterson Belknap Webb & Tyler LLP*
Thomas J. Edelman (3) (4)	*Former Chairman of the Board and Chief Executive Officer, Patina Oil & Gas Corporation*
Eric P. Grubman (1) (3)	*Executive Vice President, National Football League*
Kirby L. Hedrick (2) (3) (4)	*Former Executive Vice President, Phillips Petroleum Company*
Scott D. Urban (1) (3) (4)	*Former Group Vice President, BP*
William T. Van Kleef (1) (3)	*Former Executive Vice President and Chief Operating Officer, Tesoro Corporation*

COMMITTEE MEMBERSHIP

(1) Audit Committee
(2) Compensation, Benefits and Stock Option Committee
(3) Corporate Governance and Nominating Committee
(4) Environment, Health and Safety Committee

EXECUTIVE OFFICERS

Charles D. Davidson	*Chairman of the Board, Chief Executive Officer and Director*
David L. Stover	*President and Chief Operating Officer*
Ted D. Brown	*Senior Vice President, North America - Northern Region*
Rodney D. Cook	*Senior Vice President, International*
Susan M. Cunningham	*Senior Vice President, Exploration*
Kenneth M. Fisher	*Senior Vice President and Chief Financial Officer*
Arnold J. Johnson	*Senior Vice President, General Counsel and Secretary*
Andrea Lee Robison	*Vice President, Human Resources*

CORPORATE INFORMATION

Annual Meeting

The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 27, 2010, at 9:30 a.m. Central Time, at The Woodlands Waterway Marriott Hotel & Convention Center located at 1601 Lake Robbins Drive, The Woodlands, Texas 77380. All stockholders are cordially invited to attend.

Form 10-K

The Company's Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission, is included in this report. Additional copies are available without charge upon request by writing to Investor Relations, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610; via the Company's website: www.nobleenergyinc.com; or via the Securities and Exchange Commission's website: www.sec.gov.

Forward-Looking Statement

This 2009 Annual Report to stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 1A. Risk Factors. Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

Noble Energy, Inc.

Corporate Headquarters 100 Glenborough Drive Suite 100 Houston, Texas 77067-3610 (281) 872.3100

Investor Relations

David Larson Vice President, Investor Relations (281) 872.3100
investor_relations@nobleenergyinc.com www.nobleenergyinc.com

Independent Public Accountants

KPMG LLP

Transfer Agent and Registrar

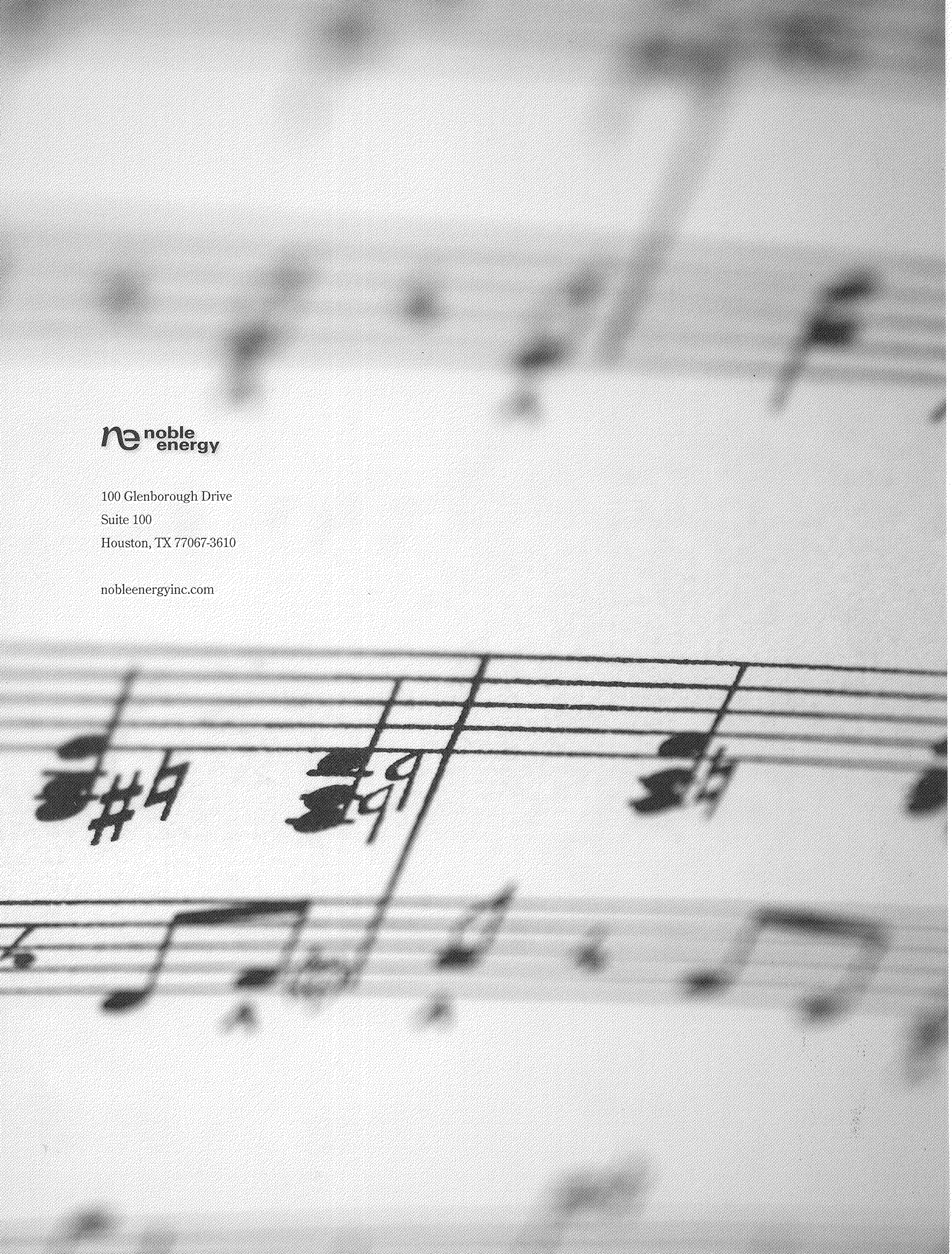
Wells Fargo Bank N.A. Shareowner Services 161 North Concord Exchange South St. Paul, MN 55075-1139
(800) 468.9716 stocktransfer@wellsfargo.com

Common Stock Listed New York Stock Exchange

Symbol - NBL

Paper used in this annual report is certified to contain 30% post consumer fiber, produced carbon neutral by a chlorine-free process. It is also green-e and green seal certified, and saves 29,733 lbs of wood, 43,418 gallons of water, 30min BTUs of energy, 9,015 lbs of emissions and 2,636 lbs of solid waste.

Stradivarius Scroll photo: Courtesy of Darnton & Hersh Fine Violins



noble energy

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