NOBLE ENERGY INC
Form 10-K
February 19, 2009

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

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2008
or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

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

Delaware	73-0785597
(State of incorporation)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100	
Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant's telephone number, including area code)

Securities registered pursuant to section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $3.33-1/3 par value	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

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

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

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

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

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

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

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2008: $17.2 billion.
Number of shares of Common Stock outstanding as of February 6, 2009: 172,913,730.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2009 Annual Meeting of Stockholders to be held on April 28, 2009, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2008, are incorporated by reference into Part III.

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PART I

Items 1 and 2. Business and Properties

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, 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, the North Sea and West Africa.

Strategy

Our strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is balanced between US and international projects. Strategic acquisitions of Patina Oil & Gas Corporation (Patina) in 2005 and U.S. Exploration Holdings, Inc. (U.S. Exploration) in 2006, along with additional capital investment in US and international locations, have resulted in substantial growth in the last several years. Acquisitions and capital investment, combined with the sale of non-core assets, have allowed us to achieve a strategic objective of enhancing our US asset portfolio, resulting in a company with assets and capabilities that include growing 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 2004-2008.

Proved Reserves

Proved reserves estimates at December 31, 2008 were as follows:

	December 31, 2008		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States			
Crude oil, condensate and NGLs (MMBbls)	121	77	198
Natural gas (Bcf)	1,268	591	1,859
Total US (MMBoe) (1)	332	176	508
International			
Crude oil, condensate and NGLs (MMBbls)	78	35	113
Natural gas (Bcf)	1,117	339	1,456
Total International (MMBoe) (1)	264	92	356
Worldwide			
Crude oil, condensate and NGLs (MMBbls)	199	112	311
Natural gas (Bcf)	2,385	930	3,315

Total Worldwide (MMBoe) (1) (2)	596	268	864

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.
(2) Approximately 69% are proved developed reserves.

Estimates of Proved Reserves – Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. For additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Reserves and Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Information.

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Reserve Audit – Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the vice president in charge of corporate reserves and certain members of senior management. In each of the years 2008, 2007 and 2006, we retained Netherland, Sewell & Associates, Inc. (NSAI), independent third-party reserve engineers, to perform reserve audits of proved reserves. A "reserve audit", as we use the term, is a process involving an independent third-party engineering firm's visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of reserve estimates. Our use of the term "reserve audit" is intended only to refer to the collective application of the procedures which NSAI was engaged to perform. The term "reserve audit" may be defined and used differently by other companies.

The reserve audit for 2008 included a detailed review of 18 of our major international, deepwater Gulf of Mexico and onshore US fields, which covered approximately 79% of US proved reserves and 97% of international proved reserves (86% of total proved reserves). The reserve audit for 2007 included a detailed review of 16 of our major international, deepwater Gulf of Mexico and onshore US fields, which covered approximately 71% of US proved reserves and 96% of international proved reserves (81% of total proved reserves). The reserve audit for 2006 included a detailed review of 14 of our major international, deepwater Gulf of Mexico and onshore US fields, which covered approximately 80% of our total proved reserves.

In connection with the 2008 reserve 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 reserve quantities, future producing rates, future net revenue, and the present value of such future net revenue. NSAI also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent Securities and Exchange Commission (SEC) staff interpretations and guidance. In the conduct of the reserve 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, 2008, 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.

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 senior engineering staff and division management with approval by the vice president in charge of corporate reserves and certain members of senior management, and are reviewed by 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 two MMBoe above to 14 MMBoe below as compared with our estimates. On a percentage basis, the NSAI field estimates ranged from 10% above our estimates to 14% 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%. At December 31, 2008, reserves differences, in the aggregate, were less than 29 MMBoe, or 4%.

Since January 1, 2008, no crude oil or natural gas reserve 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 reserve and other information, with the EIA.

Recent SEC Rule-Making Activity – In December 2008, the SEC announced that it had approved revisions to modernize its oil and gas company reporting requirements. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information.

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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.

Mid-continent Acquisition – In July 2008, we acquired producing properties in western Oklahoma for $292 million in cash. Properties acquired cover approximately 15,500 net acres and are currently producing a net 20 MMcfepd. The total purchase price has been preliminarily 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, we closed on the sale of our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. The gain on sale has been deferred as the sale is contingent upon approval of 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. Deepwater Gulf of Mexico and Gulf Coast onshore areas remain core areas and are more aligned with our long-term business strategies. See Item 8. Financial Statements and Supplementary Data—Note 4—Acquisitions and Divestitures.

U.S. Exploration Acquisition – In 2006, we acquired U.S. Exploration, a privately held corporation, for $412 million in cash plus liabilities assumed. U.S. Exploration's reserves and production are 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. See Item 8. Financial Statements and Supplementary Data—Note 4—Acquisitions and Divestitures.

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 provide 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.

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.

2009 Budget

Due to the uncertain economic and commodity price environment, we have designed a flexible capital spending program that will be responsive to conditions that develop during 2009. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – 2009 Outlook – 2009 Budget.

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. In 2008, we continued to expand our undeveloped acreage position with the leasing of approximately 502,000 net acres in Colorado, Kansas, Montana, Wyoming, East Texas and Oklahoma, along with 15 new leases in the deepwater Gulf of Mexico.

US operations accounted for 56% of our 2008 consolidated sales volumes and 59% of total proved reserves at December 31, 2008. Approximately 61% of the proved reserves are natural gas and 39% are crude oil, condensate and NGLs. Our onshore US portfolio at December 31, 2008 included 996,000 net developed acres and 1.3 million net undeveloped acres. We currently hold interests in 93 offshore blocks in the Gulf of Mexico.

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

	Year Ended December 31, 2008 Sales Volumes				December 31, 2008 Proved Reserves		
	Crude Oil (MBopd)	Natural Gas (MMcfpd)	NGLs (MBpd)	Total (MBoepd)	Crude Oil (1) (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Northern Region							
Wattenberg field	15	146	5	45	118	842	259
Piceance basin	-	39	-	7	-	263	44
Niobrara field (Tri-state area)	-	26	-	4	-	109	18
Mid-continent area	7	72	1	20	37	336	93
Other	-	25	-	4	1	122	21
Total	22	308	6	80	156	1,672	435
Southern Region							
Deepwater Gulf of Mexico	13	49	3	24	19	64	29
Gulf Coast onshore and other	5	38	-	12	23	123	44
Total	18	87	3	36	42	187	73
Total United States	40	395	9	116	198	1,859	508

(1) Includes NGLs.

Wells drilled in 2008 and productive wells at December 31, 2008 for our significant US operating areas were as follows:

	Year Ended December 31, 2008 Gross Wells Drilled/ Participated in	December 31, 2008 Gross Productive Wells
Northern Region		
Wattenberg field	558	5,731
Piceance basin	125	238
Niobrara field (Tri-State area)	243	982
Mid-continent area	93	4,178
Other	31	1,273
Total	1,050	12,402
Southern Region		
Deepwater Gulf of Mexico	3	12
Gulf Coast onshore and other	70	1,073
Total	73	1,085
Total United States	1,123	13,487

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Northern Region—The Northern region consists of our operations in the Rocky Mountains area, which includes the Denver-Julesburg (D-J) (Wattenberg field), Piceance, San Juan, and Wind River basins, as well as the Niobrara (Tri-State), Bowdoin and Siberia Ridge fields. The Northern region also includes the Mid-continent area, consisting of properties in the Texas Panhandle, Oklahoma and Kansas. The Rocky Mountains area is one of our core operating assets. During 2008, we acquired a total of approximately 490,000 net acres in southern Montana, the Mid-continent area and the Niobrara and Wattenberg fields.

Wattenberg Field—The Wattenberg field (approximately 96% operated working interest), located in the D-J 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 51% of our US proved reserves on December 31, 2008.

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.

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We continue to improve efficiencies in Wattenberg field drilling and completion operations and have significantly reduced drilling time by utilizing the latest available technology, including automatic drilling rigs (ADRs). An ADR uses an automated system to regulate the drill string of a drilling rig in response to current drilling conditions, including drilling fluid pressure, bit weight, drill string torque, and drill string revolutions per minute to achieve an optimal rate of bit penetration.

In 2008, we drilled or participated in 558 Wattenberg field development wells, with a 99.8% success rate and added approximately 186 Bcfe of proved reserves approximately 59% of which were natural gas. At year-end, we were running six drilling rigs and 15 completion units in the field.

We have experienced significant growth in production from the Wattenberg field, from an average of 199 MMcfepd at year-end 2005 to approximately 268 MMcfepd at year-end 2008. Approximately 54% of 2008 production was natural gas. However, expansion of field boundaries has resulted in a 110% increase in our crude oil and NGL stream since year-end 2005. In 2008, sales of Wattenberg field production accounted for 39% of total US sales volumes.

The infrastructure in this area is improving and expanding. Oil transport alternatives should improve in 2009 with the expected start up of a new interstate crude oil transportation pipeline system which will run from Weld County, Colorado, where the Wattenberg field is located, to Cushing, Oklahoma. The pipeline, in which we own a small equity interest, will provide another option for the marketing of our crude oil. We have entered into a five-year throughput agreement with the pipeline.

We continue to acquire acreage in the area and held interests in approximately 332,000 net acres at year-end 2008. We are planning an active capital program in 2009; however, our program may decrease from 2008 levels. We will have the flexibility with short-term drilling rig contracts to decrease activity if economic conditions continue to decline. We will continue to have a strong focus on Codell/Niobrara new drills. Additionally, we have a substantial project inventory remaining and plan to continue steady refracture, trifracture, and recompletion programs in 2009.

Piceance Basin—The Piceance basin in western Colorado (approximately 93% operated working interest) is another core area for us. It is a major North American natural gas basin, 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 significantly 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 resources in tight-gas areas such as the Piceance basin.

In 2008, we increased our drilling activities and drilled or participated in 124 development wells and one exploratory well, 100% of which were successful. Our 2008 drilling activity resulted in the addition of 135 Bcfe of proved reserves. Successful drilling activity in recent years has led to significant volume growth; production has grown from 2 MMcfepd in 2005 to 53 MMcfepd at year-end 2008.

We have assembled a significant acreage position in the area and currently hold interests in approximately 19,000 net acres providing a large inventory of future projects. At this time, we plan to operate a two-rig drilling program in 2009.

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 88% operated working interest). The Niobrara formation is an important shallow 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 are planning an active capital program in 2009; however, our program may decrease from 2008 levels. We will have the flexibility with short-term drilling rig contracts to decrease activity if economic conditions continue to decline.

In 2008, we doubled our drilling activity and drilled or participated in 243 development wells. Increased use of 3-D seismic to optimize well locations helped increase our success rate to over 80% in 2008. Our 2008 drilling activity resulted in the addition of 35 Bcfe of proved reserves, and we were producing approximately 28 MMcfepd, net at year-end. Short-term drilling rig contracts allow flexibility for our drilling plans if economic conditions continue to decline.

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Mid-continent Area—The Mid-continent area includes properties in the Texas Panhandle, Oklahoma and Kansas. Significant areas of activity have been the Granite Wash development in the Texas Panhandle, infill drilling in several of our Oklahoma waterfloods, and deeper completions to the Skinner formation in western Oklahoma. We drilled or participated in 92 development wells in 2008, 96% of which were successful and one successful exploratory well. The potential for Granite Wash horizontal drilling is currently being evaluated, which, if successful, could increase the recovery of reserves in place and daily production rates.

In July 2008, we expanded into a new area with a 15,500 net acre acquisition in western Oklahoma, which included approximately 16 MMboe of proved reserves. The target area is the Cleveland Sandstone, a tight gas play characterized by low-permeability rock. Since acquiring the property we have drilled seven development wells (included in the well count above). There are currently 56 operated wells on the property producing in aggregate a net 20 MMcfepd. We have the flexibility of operating one to three rigs in 2009 with two rigs currently operating.

Other—We are also active in the Bowdoin field (approximately 63% operated working interest), located in north central Montana; the San Juan basin (approximately 82% operated working interest), located in northwestern New Mexico and southwestern Colorado; and the Wind River basin (approximately 74% operated working interest), located in central Wyoming. In 2008, we drilled or participated in a total of 31 development wells in these areas, 100% of which were successful. We plan to have reduced activity in these areas in 2009 as we focus most of our capital spending on the core development fields of Wattenberg, Piceance and Tri-State.

During 2008, we acquired approximately 205,000 net exploratory acres in southern Montana and plan to test the area in 2009.

Southern Region—The Southern region includes the deepwater Gulf of Mexico and onshore areas primarily in Texas, Louisiana, Illinois and Indiana. In 2006, we sold all of our significant Gulf of Mexico shelf properties except for the Main Pass area, which is currently held for sale. The sale of our shelf properties allowed us to migrate future investments and growth from the Gulf of Mexico shelf to the deepwater Gulf of Mexico which we believe is an area of higher potential.

Deepwater Gulf of Mexico—The deepwater Gulf of Mexico is one of our core areas and accounted for 21% of 2008 US sales volumes and 6% of US proved reserves at December 31, 2008. We currently hold interests in 93 deepwater Gulf of Mexico leases, representing approximately 315,000 net acres. We operate approximately 70% of the leases.

The expansion of our deepwater Gulf of Mexico program began in 2004 with the Ticonderoga discovery and the acquisition of additional ownership interests in Swordfish and Lorien. Since then we have continued to expand our operations primarily through an active exploration program, expansion of our 3-D seismic database, and lease acquisition. Our exploration activities have led to significant discoveries at Isabela and Redrock/Raton, and, most recently, Gunflint, a 2008 discovery which is our largest deepwater Gulf of Mexico discovery to date. Participation in the 2008 central Gulf of Mexico outer continental shelf sale resulted in our being awarded 15 new deepwater Gulf of Mexico leases for approximately $167 million, net to our interest, and allows us to expand our inventory with the addition of several new deepwater Gulf of Mexico prospects in the Atwater Valley, Mississippi Canyon, Green Canyon, Walker Ridge, and Garden Banks areas.

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In addition to Gunflint, 2008 exploration drilling activities included a well at the Noble-operated Tortuga prospect (Mississippi Canyon Blocks 561 and 605; 57% working interest). Although the well was successful in locating hydrocarbons, we decided not to develop the prospect due to near-term lease expiration as well as other considerations. Accordingly, we impaired the well in the fourth quarter of 2008. We also announced that an exploration well at the Stones River prospect (Mississippi Canyon Block 285; 100% working interest) did not encounter hydrocarbons in commercial quantities.

We plan to continue exploration activities in 2009 by conducting a seismic program and drilling two to three exploratory wells.

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% working interest) – We originally acquired the block in the 2006 central Gulf of Mexico outer continental shelf sale and announced the Gunflint crude oil discovery, our largest deepwater Gulf of Mexico discovery to date, in October 2008. We are currently acquiring additional seismic information and preparing to drill an appraisal well in 2009 or early 2010. We are the operator of the block.

Isabela (Mississippi Canyon Block 562, 33% working interest) – Isabela was a 2007 discovery and is non-operated. Development planning is underway, Phase 1 of which is anticipated to include a producing well with a subsea tieback to an existing production facility. Initial production is currently anticipated in 2011. We also have an interest in adjacent acreage with additional exploration potential on Mississippi Canyon Blocks 519 and 563 (23.25% working interest). We are currently drilling an exploratory well on Block 519 (Santa Cruz prospect).

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 Raton South appraisal well was also drilled during 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 Raton South, and tie back to a host facility is anticipated in late 2009. Redrock is currently considered a co-development candidate to the completed sidetrack well at Raton South. 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. In 2007, we drilled and completed a sidetrack to Viosca Knoll Block 917 #1 well, which began production at the end of 2007. 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. In 2007, we drilled and completed the #3 and #1 ST4 wells to extend and enhance production from the field. The wells came on line first quarter 2008. The project currently includes three producing wells connected to existing infrastructure through subea tiebacks.

Lorien (Green Canyon Block 199; 60% working interest) – Lorien was a 2003 crude oil discovery and began producing in 2006. The project currently includes two producing wells connected to existing infrastructure through subea tiebacks. We are the operator of Lorien.

In September 2008, Hurricanes Gustav and Ike moved through the Gulf of Mexico. Inspection of our facilities and equipment indicated there was no major damage from the hurricanes, although damage to third party processing and pipeline facilities has slowed reinstatement of production from our Gulf of Mexico assets, including Lorien and Ticonderoga. Approximately 8.5 MBoepd of production remained shut-in at year-end. We expect production to resume during the first half of 2009, depending on the successful resumption of pipeline and other non-operated facilities.

New Albany Shale—We continue to selectively increase our acreage position in resource plays, including shale plays. We have accumulated over 179,000 net acres in the New Albany Shale in the Illinois Basin (approximately 92% working interest), located in Indiana and Illinois. During 2008, we drilled 11 development wells, 100% of which were successful. We also drilled 12 development wells in the Paxton area, 92% of which were successful, and seven successful exploration wells on our Round Rock acreage in the Illinois Basin.

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East Texas and North Louisiana—This is an emerging area for us. Recent acquisitions have increased our leasehold acreage to approximately 17,700 net acres. In 2008, we drilled seven horizontal James Lime wells and 24 Hosston, Travis Peak and Cotton Valley wells, all of which were successful. We also participated in the drilling of one successful horizontal Haynesville shale well in North Louisiana. Our drilling program for 2009 will focus on the Haynesville shale.

Other— In addition to the East Texas and North Louisiana programs, we drilled six successful development wells within the South Central Robertson Unit in west Texas and two Gulf Coast exploratory wells.

International

International operations are significant to our business, accounting for 44% of consolidated sales volumes in 2008 and 41% of total proved reserves at December 31, 2008. International proved reserves are approximately 68% natural gas and 32% crude oil. Operations in Equatorial Guinea, Cameroon, Ecuador, China and Suriname are conducted in accordance with the terms of production sharing contracts. Operations in 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, 2008 Sales Volumes				December 31, 2008 Proved Reserves		
	Crude Oil (MBopd)	Natural Gas (MMcfpd)	NGL's (MBpd)	Total (MBoepd)	Crude Oil (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
International							
West Africa	15	206	-	49	75	978	238
North Sea	10	5	-	11	23	19	27
Israel	-	139	-	23	-	273	46
Ecuador	-	22	-	4	-	180	30
China	4	-	-	4	15	6	15
Total consolidated	29	372	-	91	113	1,456	356
Equity investee	2	-	6	8			
Total	31	372	6	99	113	1,456	356
Equity investee share of methanol sales (MMgal)				119			

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Wells drilled in 2008 and productive wells at December 31, 2008 in our international operating areas were as follows:

	Year Ended December 31, 2008 Gross Wells Drilled/Participated in	December 31, 2008 Gross Productive Wells
International		
West Africa	3	23
North Sea	4	26
Israel	-	6
Ecuador	-	5
China	-	15
Suriname	1	-
Total International	8	75

West Africa (Equatorial Guinea and Cameroon)—Operations in West Africa accounted for 54% of 2008 consolidated international sales volumes and 67% of international proved reserves at December 31, 2008. At December 31, 2008, we held approximately 15,000 net developed acres and 250,000 net undeveloped acres in Equatorial Guinea and 563,000 net undeveloped acres in Cameroon. In 2008, approximately 190,000 gross undeveloped acres were relinquished in Equatorial Guinea pursuant to contract terms.

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. We sell our share of condensate produced in the Alba field and from the LPG plant under short-term contracts at market-based prices.

West Africa Exploration Activities — We have conducted a successful exploration and appraisal drilling program in West Africa, which centers around Blocks O and I, offshore Equatorial Guinea, and the PH-77 license, offshore Cameroon. We are the technical operator on Block O (45% working interest) and Block I (40% working interest) and the operator on the PH-77 license (50% working interest).

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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.

We are in the process of assessing our options to commercialize our discoveries in the region. Engineering studies are underway, and we expect to utilize a phased-in approach for development. A development plan for the Benita discovery on Block I was submitted to the Equatorial Guinean government in December 2008, and we await their approval. We anticipate sanction of the Benita project to occur in 2009, with first oil production planned for 2012. The Benita development is expected to include subsea tie-backs to a floating production, storage and offloading vessel (FPSO). We are also evaluating options for natural gas production and marketing.

North Sea—Operations in the North Sea (the Netherlands and the UK) comprise another core international asset. We have been conducting business in the North Sea 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 13% of 2008 consolidated international sales volumes and 8% of international proved reserves at December 31, 2008. During 2008, we relinquished approximately 159,000 gross undeveloped acres. At December 31, 2008, we held approximately 6,000 net developed acres and 54,000 net undeveloped acres.

We produce from the Dumbarton, MacCulloch, Hanze, Cook and other fields. Most of our production is from the non-operated Dumbarton Phase I development (30% working interest) in blocks 15/20a and 15/20b in the UK sector of the North Sea. The Dumbarton development, which was completed and began production in 2007, includes a subsea tie-back to the GP III, an FPSO in which we own a 30% interest.

In 2008, we continued the development of Dumbarton (30% working interest) with Phase 2. Phase 2 involves drilling up to six new horizontal production wells and up to two water disposal wells. The first two wells in Phase 2 were brought online in 2008, increasing the total field production to approximately 40,000 Bopd, gross. With the additional two wells, Dumbarton now has seven horizontal producers and two water injection wells. Phase 2 drilling will continue into 2009. As part of the project we plan to participate in the development of the Lochranza discovery in block 15/20a (30% working interest) which includes drilling two horizontal production wells which will be tied back to the Dumbarton subsea facilities.

During 2008, we also participated in drilling the Morgan exploratory well, in the UK Central North Sea (40% working interest). The well did not contain hydrocarbons in commercial quantities.

Israel—Operations in Israel accounted for 25% of 2008 consolidated international sales volumes and 13% of international proved reserves at December 31, 2008. At December 31, 2008, we held approximately 29,000 net developed acres and 807,000 net undeveloped acres located between 10 and 60 miles offshore Israel in water depths ranging from 700 feet to 5,500 feet. Our leasehold position in Israel includes one preliminary permit, two leases and three licenses. We are the operator of our Israel properties.

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 has peak field deliverability of approximately 600 MMcfpd from six wells. In 2008, we commissioned a permanent onshore receiving terminal in Ashdod for distribution of natural gas from the Mari-B field to purchasers.

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 139 MMcfpd in 2008. The Israel Electric Corporation

Limited (IEC) is our largest purchaser. The IEC has continued to convert power plants to use natural gas as fuel and, in 2008, the IEC power plant at Gezer began purchasing natural gas from us. We also sell to the Bazan Oil Refinery, Delek Independent Power Production and associated desalinization plant, and a paper mill. In 2008, we entered a new five-year natural gas sales contract with Israel Chemicals Ltd, with sales expected to begin in 2009. In addition, the IEC power plant at Hagit is expected to begin purchasing natural gas from us in 2009. Imports of natural gas from Egypt to Israel began in 2008. However, there is still potential for significant new sales in the future as the Israeli infrastructure and markets continue to expand.

We are continuing exploration activities in Israel. In fourth quarter 2008, we began drilling an exploration well to test the Tamar prospect (36% working interest), offshore northern Israel, and in January 2009, we announced a very significant natural gas discovery at Tamar. In February 2009, we announced a successful test of production flow rates at Tamar as well as our plans to drill an appraisal well later in the year. We have conducted additional seismic activities in the area and are conducting a compression study at the Mari-B field.

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Other International—Other international at December 31, 2008 includes the following:

Ecuador—Operations in Ecuador accounted for 4% of 2008 consolidated international sales volumes and 8% of international proved reserves at December 31, 2008. The concession covers approximately 12,000 net developed acres and 852,000 net undeveloped acres.

We have been operating in Ecuador since 1996. We utilize natural gas from the Amistad field (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 2008, power generation totaled 749 GW hours.

China — We have been engaged in exploration and development activities in China since 1996 with production beginning in 2003. We are operator for the joint operating group of the Cheng Dao Xi field (57% working interest), which is located in the shallow water of the southern Bohai Bay. In 2008, activities consisted primarily of workover operations, including installations of electric submersible pumps. China accounted for 4% of 2008 consolidated international sales volumes and 4% of international proved reserves at December 31, 2008. At December 31, 2008, we held approximately 4,000 net developed acres and no undeveloped acres. The Supplemental Development Plan, which is designed to further develop the Cheng Dao Xi field through additional drilling and facilities construction, has received all necessary governmental approvals.

Suriname — Suriname, a country located on the northern coast of South America, represents a new exploration area for us. We have entered into participation agreements on non-operated Block 30 (45% working interest) and on Block 32 (100% working interest), which combined cover approximately 6.4 million net acres offshore. During 2008, we participated in the drilling of an exploratory well on the West Tapir prospect on Block 30. The well, which did not contain hydrocarbons in commercial quantities, was the first well to be drilled offshore Suriname in over 20 years and the drilling results will allow us to evaluate and improve our understanding of the basin. We will incorporate the findings into our geological and geophysical interpretations, which will influence our risk assessment of the remaining prospects.

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

	Sales Volumes			Average Sales Price			Average Production Cost
	Crude Oil MBopd (1)	Natural Gas MMcfpd	NGLs MBpd	Crude Oil Per Bbl (2)	Natural Gas Per Mcf (2)	NGLs Per Bbl	Per BOE (3)
Year Ended December 31, 2008							
United States	40	395	9	$ 75.53	$ 8.12	$ 50.15	$ 10.43
West Africa (4) (5)	15	206	-	88.95	0.27	-	2.17
North Sea	10	5	-	100.56	10.54	-	14.30
Israel	-	139	-	-	3.10	-	1.07
Ecuador	-	22	-	-	-	-	-
Other International (6)	4	-	-	82.66	-	-	15.94
Total Consolidated Operations	69	767	9	82.60	5.04	50.15	$ 7.84
Equity Investee (7)	2	-	6	96.77	-	58.81	
Total	71	767	15	$ 82.96	$ 5.04	$ 53.45	
Year Ended December 31, 2007							
United States	42	412	-	$ 53.22	$ 7.51	-	$ 8.49
West Africa (4) (5)	15	132	-	71.27	0.29	-	2.89
North Sea	13	6	-	76.47	6.54	-	9.81
Israel	-	111	-	-	2.79	-	1.14
Ecuador	-	26	-	-	-	-	-
Other International (6)	7	-	-	53.69	-	-	12.06
Total Consolidated Operations	77	687	-	60.61	5.26	-	$ 6.99
Equity Investee (7)	2	-	6	74.87	-	48.87	
Total	79	687	6	$ 60.94	$ 5.26	$ 48.87	
Year Ended December 31, 2006							
United States	46	452	-	$ 50.68	$ 6.61	-	$ 8.12
West Africa (4) (5)	18	45	-	62.51	0.37	-	2.86
North Sea	4	8	-	67.43	8.00	-	10.08
Israel	-	93	-	-	2.72	-	1.60
Ecuador	-	25	-	-	-	-	-
Other International (6)	7	-	-	52.05	-	-	9.74
Total Consolidated Operations	75	623	-	54.47	5.55	-	$ 6.97
Equity Investee (7)	2	-	6	66.60	-	40.10	
Total	77	623	6	$ 54.75	$ 5.55	$ 40.10	

(1) In 2008, volumes include the effect of crude oil sales in excess of volumes produced of 1 MBopd in West Africa. During 2007, crude oil sales volumes equaled volumes produced. In 2006, volumes include the effect of crude oil sales in excess of volumes produced of 1 MBopd in West Africa and crude oil sales less than volumes produced of 1 MBopd in other international.

(2) Average crude oil sales prices for the US reflect reductions of $22.06 per Bbl (2008), $13.68 per Bbl (2007), and $11.41 per Bbl (2006) from hedging activities. Average crude oil sales prices for West Africa reflect reductions of

$7.59 per Bbl (2008) and $2.19 per Bbl (2007) from hedging activities. We did not hedge West Africa crude oil sales in 2006. Average natural gas sales prices in the US reflect an increase of $0.23 per Mcf (2008), an increase of $1.12 per Mcf (2007), and a reduction of $0.25 per Mcf (2006) from hedging activities.

(3) Average production costs include oil and gas operating costs, workover and repair expense, production and ad valorem taxes, and transportation expense.

(4) 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. 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. The price on an Mcf basis has been adjusted to reflect the Btu content of gas sales.

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(5) Equatorial Guinea natural gas volumes include sales to the LNG plant of 163 MMcfpd for 2008 and 78 MMcfpd for 2007. There were no natural gas sales to the LNG plant before 2007.
(6) Other International crude oil volumes include China and Argentina (through February 2008). Other International natural gas volumes include Argentina (through February 2008).
(7) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea.

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, 2008, our operated properties accounted for approximately 61% 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 as of December 31, 2008 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States						
Northern Region	7,567	5,853.8	4,835	3,384.6	12,402	9,238.4
Southern Region	833	796.0	252	105.7	1,085	901.7
West Africa	3	1.2	20	7.7	23	8.9
North Sea	17	3.5	9	1.2	26	4.7
Israel	-	-	6	2.8	6	2.8
Ecuador	-	-	5	5.0	5	5.0
China	14	8.0	1	0.6	15	8.6
Total	8,434	6,662.5	5,128	3,507.6	13,562	10,170.1
Multiple Completions	-	-	16	3.3	16	3.3

Productive wells are producing wells and wells 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. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. 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, 2008 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States	(in thousands)			
Onshore	1,352	893	1,361	1,014
Offshore	164	103	556	300
Total United States	1,516	996	1,917	1,314
International				
Equatorial Guinea	45	15	618	250
Cameroon	-	-	1,125	563

North Sea (1)	48	6	266	54
Israel	62	29	1,823	807
Ecuador	12	12	852	852
China	7	4	-	-
Suriname	-	-	7,740	6,363
Other International (2)	-	-	1,830	1,142
Total International	174	66	14,254	10,031
Total Worldwide (3)	1,690	1,062	16,171	11,345

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(1) The North Sea includes acreage in the UK and the Netherlands. In 2008, we sold our interest in Norway acreage consisting of approximately 411,000 gross (127,000 net) undeveloped acres.
(2) Other International includes India and Cyprus.
(3) Approximately 258,000 gross acres (176,000 net acres) will expire in 2009, 662,000 gross acres (385,000 net acres) will expire in 2010, and 1,370,000 gross acres (1,285,000 net acres) will expire in 2011 if production is not established or we take no other action to extend the terms.

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 (1)	Dry	Total
Year Ended December 31, 2008						
United States						
Northern Region	1.0	-	1.0	837.2	42.0	879.2
Southern Region	14.6	2.0	16.6	30.9	2.0	32.9
West Africa	1.3		1.3	-	-	-
North Sea	-	0.4	0.4	0.6	0.3	0.9
Israel	-	-	-	-	-	-
Suriname	-	0.5	0.5	-	-	-
Total	16.9	2.9	19.8	868.7	44.3	913.0
Year Ended December 31, 2007						
United States						
Northern Region	13.9	1.9	15.8	738.0	24.5	762.5
Southern Region	0.3	2.6	2.9	19.6	3.1	22.7
West Africa	2.6	0.5	3.1	-	-	-
North Sea	0.5	-	0.5	-	-	-
Israel	-	-	-	0.4	-	0.4
Argentina (2)	-	0.1	0.1	6.7	-	6.7
Total	17.3	5.1	22.4	764.7	27.6	792.3
Year Ended December 31, 2006						
United States						
Northern Region	5.5	4.6	10.1	521.4	4.6	526.0
Southern Region	0.8	4.4	5.2	145.2	0.9	146.1
West Africa	-	0.4	0.4	1.8	-	1.8
North Sea	-	-	-	1.1	-	1.1
Argentina (2)	-	-	-	7.6	-	7.6
Total	6.3	9.4	15.7	677.1	5.5	682.6

(1) Excludes wells drilled but not yet completed.
(2) Our assets in Argentina were sold February 2008.

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

An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the table above and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. 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 the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency.

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In addition to the wells drilled and completed in 2008 included in the table above, at December 31, 2008, we were in the process of drilling or completing 269 gross (215.4 net) wells in the Northern region of our US operations, two gross (1.2 net) onshore wells in the Southern region of our US operations, one gross (0.5 net) well in Equatorial Guinea, and one gross (0.4 net) well in Israel.

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 also engage in the purchase and sale of third-party crude oil and natural gas production. Such third-party production may be purchased from non-operators who own working interests in our wells or from other producers' properties in which we own no interest. We sell our natural gas production at both market-based and fixed prices. In 2008, approximately 15% 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.

Significant Purchaser—Suncor Energy Marketing (Suncor) was the largest single non-affiliated purchaser of 2008 production and purchased our share of crude oil from the Wattenberg field in Colorado. Sales to Suncor accounted for 22% of 2008 crude oil sales, or 13% of 2008 total oil and gas sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2008. 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 2008 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, to achieve a more predictable cash flow by reducing our exposure to commodity price fluctuations. For additional information, see Item 1A. Risk Factors—Hedging transactions may limit our potential gains and Hedging transactions, receivables and cash investments expose us to counterparty credit risk, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

Regulations

Government Regulation—Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated at the international, federal, state 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.

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 and the Minerals Management Service, 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 Environmental Protection Agency 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

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Clean Water Act and the Occupational Safety and Health Act have certain authority over environmental, health and safety matters affecting our operations as discussed below;

- 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.

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, more recently, the same commission's December 10, 2008 approval of a comprehensive update to statewide rules governing oil and gas operations in Colorado. These rules will be reviewed by the Colorado legislature in its 2009 session and will become 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 US Environmental Protection Agency, 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 Petroleum and Mines, the Equatorial Guinea Ministry of Mines, Industry and Energy 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 US Environmental Protection Agency 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 US Environmental Protection Agency, 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.

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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 and income 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 acquisition, exploration, development and production: United States, West Africa, North Sea, Israel, and Other International, Corporate and Marketing. For more information, see Item 8. Financial Statements and Supplementary Data—Note 15—Segment Information.

Employees

Our total number of employees increased during the year from 1,398 at December 31, 2007 to 1,571 at December 31, 2008. The 2008 year-end employee count includes 182 foreign nationals working as employees in Ecuador, China, Israel, the UK, Equatorial Guinea and Cameroon.

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 are not so material as to detract substantially 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 “Investor Relations—Investor Relations 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.

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In 2008, we submitted the annual certification of our Chief Executive Officer regarding compliance with the NYSE's corporate governance listing standards, pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

Item 1A. Risk Factors

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 2008 ranged from a high of $145.29 per barrel to a low of $33.87 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2008 ranged from a high of $13.58 per MMBtu to a low of $5.29 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 foreign imports;
- the price and availability of alternative fuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- electricity dispatch;
- 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, ability to finance planned capital expenditures and results of 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;
- reducing the carrying value of our crude oil and natural gas properties; or
- limiting our access to sources of capital, such as equity and long-term debt.

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 many 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. Our reserve estimates are based on year-end commodity prices; therefore, reserve 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 reserve 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, reserve 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.

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Additionally, because some of our reserve 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.

Failure to fund continued capital expenditures could adversely affect our properties.

Our acquisition, exploration, and development 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 program in West Africa. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity 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 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 debt, equity or other methods of financing on an economic basis to meet these requirements, particularly in the current economic environment. If we are not able to fund our capital expenditures, interests in some properties might be reduced or forfeited as a result.

The current recession could have a material adverse impact on our financial position, results of operations and cash flows.

The oil and gas industry is cyclical in nature and tends to reflect general economic conditions. The US and other world economies are in a recession which could last well into 2009 and beyond. The recession may lead to significant fluctuations in demand and pricing for our crude oil and natural gas production, such as the decline in commodity prices which occurred during 2008 and into 2009. Our profitability will likely be significantly affected by decreased demand and lower commodity prices. Due to lower commodity prices, we recorded asset impairment charges during fourth quarter 2008. If commodity prices continue to decline, there could be additional impairments of our operating assets or an impairment of goodwill. Our future access to capital, as well as that of our partners and contractors, could be limited due to tightening credit markets that could inhibit development of our property interests. Some of our longer term projects require significant investment and may be delayed due to capital constraints. In addition, 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.

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 consolidated sales volumes in 2008 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.

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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.

We may be unable to make attractive acquisitions or integrate acquired businesses and/or assets, and any inability to do so may disrupt 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 and our purchase of U.S. Exploration. 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 or even if such capital is available on commercially acceptable terms. Additionally, if we acquire another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could 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 would be realized.

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.

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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.

Potential regulations regarding climate change could alter the way we conduct our business.

As awareness of climate change issues increases, governments around the world are beginning to address the matter. This may result in new environmental regulations that may unfavorably impact 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.

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.

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. 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 reasonable. 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.

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. This highly competitive environment could have an adverse impact on our business.

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Our level of indebtedness may limit our financial flexibility.

As of December 31, 2008, we had long-term indebtedness of $2.2 billion (excluding unamortized discount), with $1.6 billion drawn under our bank credit facility. Our indebtedness represented 26% of our total book capitalization at December 31, 2008.

Our level of 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 current credit market crisis which has 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 acquisition, exploration and development activities. A higher level of indebtedness increases the risk that we may 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 manage our exposure to price risks in 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 four 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. In trying to manage our exposure to 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 future 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 any decline in crude oil or natural gas prices.

Hedging transactions, receivables and cash investments expose us to counterparty credit risk.

Our hedging transactions also 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. We also monitor the creditworthiness of our counterparties on an ongoing basis. However, the current disruptions occurring 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 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.

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

In addition to hedging transactions, we are exposed to risk of financial loss from trade and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of these parties 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 from our largest international crude oil purchaser; however, we do not have all of our trade credit enhanced through guarantees or credit support. Nonperformance by a trade creditor could result in significant financial losses.

We have over $1.0 billion in cash and cash equivalents, including investments in US Treasury securities and short-term cash investments with major financial institutions. In response to the credit market crisis, we have shortened the duration of our investment maturities and have increased our investments in US Treasury securities. 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.

Information technology systems implementation issues could disrupt our internal operations, increase our costs and adversely affect our financial results or our ability to report our financial results.

We have been in the process of implementing a new Enterprise Resource Planning software system to replace our various legacy systems. Our implementation is based on a phased approach, the first phase of which was implemented fourth quarter 2007. We implemented additional phases in 2008 and expect to implement additional phases in 2009. As a part of this effort, we are transitioning data and changing certain processes and this may be more expensive, time consuming and resource intensive than planned. Any disruptions that may occur in the implementation or operation of this system or any future systems could increase our expenses and adversely affect our ability to report in an accurate and timely manner our financial position, results of operations and cash flows and to otherwise operate our business.

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 stockholders. 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 stockholders.

Disclosure Regarding Forward-Looking Statements

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

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our acquisition, exploration and development activities;
- our outlook on global economic conditions and markets;

- 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.

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Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

Purchaser Bankruptcy – We have 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.

As of December 31, 2008, we had a receivable of approximately $71 million from SemCrude. We have determined that it is probable that a portion of the receivable is uncollectible. Therefore, in third quarter 2008, we reduced the carrying value of the SemCrude receivable and recognized a pre-tax charge of $38 million for the probable loss. We are pursuing various legal remedies to protect our interests. We believe that ultimate disposition of this matter will not have a material adverse affect on our financial position, results of operations, or cash flows.

Legal Proceedings – We are among a group of 18 defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930's. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. Dore has delivered documents alleging approximately $140 million in damages. Trial is currently set for April 27, 2009. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our financial position, results of operations, or cash flows.

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 during the fourth quarter of 2008.

Executive Officers

The following table sets forth certain information, as of February 19, 2009, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	58	Chairman of the Board, President, Chief Executive Officer and Director
David L. Stover (2)	51	Executive Vice President, Chief Operating Officer
Chris Tong (3)	52	Senior Vice President, Chief Financial Officer
Ted D. Brown (4)	53	Senior Vice President, Northern Region
Rodney D. Cook (5)	51	Senior Vice President, International
Susan M. Cunningham (6)	53	Senior Vice President, Exploration
Arnold J. Johnson (7)	53	Senior Vice President, General Counsel and Secretary
Andrea Lee Robison (8)	50	Vice President, Human Resources

(1) Charles D. Davidson was elected President and Chief Executive Officer of Noble Energy in October 2000 and Chairman of the Board in April 2001. 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 Executive Vice President and Chief Operating Officer of Noble Energy in August 2006. Prior thereto, he served as Senior Vice President of North America and Business Development from July 2004 through July 2006. 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.

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(3) Chris Tong was elected a Senior Vice President and Chief Financial Officer of Noble Energy in January 2005. Prior to January 2005, he had served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. since August 1997. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions since August 1996, and served in other treasury positions with Tejas beginning August 1989. From 1980 to 1989, Mr. Tong served in various energy lending capacities with several commercial banking institutions. Prior to his banking career, Mr. Tong served over a year with Superior Oil Company as a Reservoir Engineering Assistant.

(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 in 1980 as a geologist and held various exploration and development positions 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.

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PART II

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

Common Stock. Our common stock, $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 common stock on the NYSE and quarterly dividends paid per share were as follows:

	High	Low	Dividends Per Share
2007			
First quarter	$ 60.69	$ 46.33	$ 0.075
Second quarter	65.50	58.81	0.120
Third quarter	70.55	58.17	0.120
Fourth quarter	81.64	69.69	0.120
2008			
First quarter	$ 81.35	$ 69.18	$ 0.120
Second quarter	103.83	75.79	0.180
Third quarter	102.79	51.18	0.180
Fourth quarter	54.01	33.15	0.180

On January 27, 2009, the Board of Directors declared a quarterly cash dividend of 0.18 cents per common share, which will be paid February 23, 2009 to shareholders of record on February 9, 2009.

Transfer Agent and Registrar. The transfer agent and registrar for the 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 6, 2009, the number of holders of record of common stock was 775.

Stock Repurchases. We did not repurchase any of our common stock in the fourth quarter of 2008.

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, 2008.

Plan Category	Number of securities to be issued upon exercise of outstanding options (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)

Equity compensation plans approved by security holders	6,082,375	$ 41.41	5,319,463
Equity compensation plans not approved by security holders	-	-	-
Total	6,082,375	$ 41.41	5,319,463

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Stock Performance Graph. This graph shows our cumulative total shareholder return over the five-year period from December 31, 2003, to December 31, 2008. 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, 2008, our peer group of companies consisted of the following:

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

The comparison assumes $100 was invested on December 31, 2003, in our common stock, in the S&P 500 Index and in our peer group and assumes that all of the dividends were reinvested.

	12/03	12/04	12/05	12/06	12/07	12/08
Noble Energy, Inc.	$ 100.00	$ 139.34	$ 182.87	$ 223.97	$ 365.44	$ 228.44
S&P 500	100.00	110.88	116.33	134.70	142.10	89.53
Peer Group	100.00	133.07	208.21	207.03	300.86	187.65

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Item 6. Selected Financial Data

	Year Ended December 31,				
	2008	2007	2006 (1)	2005 (2)	2004
	(in millions, except as noted)				
Revenues and Income					
Total revenues	$ 3,901	$ 3,272	$ 2,940	$ 2,187	$ 1,351
Income from continuing operations	1,350	944	678	646	314
Net income	1,350	944	678	646	329
Per Share Data					
Basic earnings per share -					
Income from continuing operations	$ 7.83	$ 5.52	$ 3.86	$ 4.20	$ 2.69
Net income	7.83	5.52	3.86	4.20	2.82
Cash dividends	0.660	0.435	0.275	0.150	0.100
Year-end stock price	49.22	80.66	49.07	40.30	30.83
Basic weighted average shares outstanding	173	171	176	154	117
Cash Flows					
Net cash provided by operating activities	$ 2,285	$ 2,017	$ 1,730	$ 1,240	$ 708
Additions to property, plant and equipment	1,971	1,414	1,357	786	554
Acquisitions	292	-	412	1,111	-
Financial Position					
Cash and cash equivalents	1,140	660	153	110	180
Commodity derivative instruments - current	437	15	35	29	29
Property, plant, and equipment, net	9,004	7,945	7,171	6,199	2,181
Goodwill	759	761	781	863	-
Total assets	12,384	10,831	9,589	8,878	3,436
Long-term obligations -					
Long-term debt	2,241	1,851	1,801	2,031	880
Deferred income taxes	2,174	1,984	1,758	1,201	180
Commodity derivative instruments	2	83	329	758	10
Asset retirement obligations	184	131	128	279	175
Other	300	337	275	280	69
Shareholders' equity	6,309	4,809	4,114	3,090	1,460
Operations Information					
Consolidated crude oil sales (MBopd)	69	77	75	57	44
Average realized price ($/Bbl) (3)	$ 82.60	$ 60.61	$ 54.47	$ 45.35	$ 34.48
Consolidated natural gas sales (MMcfpd)	767	687	623	508	367
Average realized price ($/Mcf) (3)	$ 5.04	$ 5.26	$ 5.55	$ 5.78	$ 4.76
Consolidated NGL sales (MBpd) (4)	9	-	-	-	-
Average realized price ($/Bbl)	$ 50.15	$ -	$ -	$ -	$ -
Proved Reserves					
Crude oil, condensate and NGL reserves (MMBbl)	311	329	296	291	193
Natural gas reserves (Bcf)	3,315	3,307	3,231	3,091	1,987
Total reserves (MMBoe)	864	880	835	806	525
Number of employees	1,571	1,398	1,243	1,171	559

(1) Includes effect of acquisition of U.S. Exploration and sale of Gulf of Mexico shelf properties. See Item 8. Financial Statements and Supplementary Data—Note 4—Acquisitions and Divestitures for additional information.
(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.

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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, the North Sea and West Africa.

Our 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.

Financial and Operating Results - 2008 was a successful year for us as evidenced by our record earnings, cash flows provided by operating activities and production. We extended our acreage position both onshore and offshore US and pursued new exploration opportunities in the deepwater Gulf of Mexico and international locations which led to significant new discoveries. We funded our capital program primarily with cash flows from operations and increased our ending cash balance.

Our financial results included the following:

- net income of $1.4 billion, a 43% increase over 2007;
- $440 million gain on commodity derivative instruments;
- diluted earnings per share of $7.58, a 39% increase over 2007;
- cash flows provided by operating activities of $2.3 billion, a 13% increase over 2007;
- $294 million asset impairment charges;
- $38 million write-down of receivable from Semcrude, L.P.;
- year-end cash balance of $1.1 billion, a $480 million increase over the prior year ending cash balance; and
- year-end ratio of debt-to-book capital of 26% as compared with 28% at December 31, 2007.

Significant operational highlights included the following:

- significant oil discovery at the Gunflint prospect in the deepwater Gulf of Mexico;
- continued production growth in the Rocky Mountains area of our US operations;
- successful Benita oil appraisal well, offshore Equatorial Guinea;
- exploration discoveries offshore Equatorial Guinea at Diega and Felicita;
- start-up of Phase 2 at the North Sea Dumbarton development;
- acquisition of producing properties in western Oklahoma;
- expanded acreage position onshore North America;
- successful appraisal of the South Raton discovery in the deepwater Gulf of Mexico;
- production start-up at the Raton gas development in the deepwater Gulf of Mexico;
- new Ticonderoga development wells brought online in the deepwater Gulf of Mexico;
- successful high bids on 15 deepwater Gulf of Mexico lease blocks in the central Gulf of Mexico lease sale; and
- record annual natural gas production in Israel of 139 MMcfpd.

In addition, in January 2009, we announced a very significant natural gas discovery at the Tamar prospect offshore Israel.

Impact of Recession and Current Credit and Commodity Markets –The US and other world economies are currently in a recession which could last well into 2009 and beyond. Additionally, the credit markets are experiencing significant volatility, and many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our primary exposure to the current credit market crisis includes our revolving credit facility, cash investments and counterparty nonperformance risks.

Our revolving credit facility is committed in the amount of $2.1 billion until December 2011, at which time it reduces to $1.8 billion. As of December 31, 2008, we had $494 million available credit under the facility. If not extended, the credit facility matures in December 2012. Should current credit market tightening be prolonged for several years, future extensions of our credit facility may contain terms that are less favorable than those of our current credit facility.

Current market conditions also elevate the concern over our cash investments, which total $1.1 billion, and counterparty risks related to our commodity derivative contracts and trade credit. With regard to our cash investments, we invest in highly liquid, investment-grade securities, US Treasury securities and short-term deposits with major financial institutions. In response to the credit market crisis, we have shortened the duration of our investment maturities and have increased our investments in US Treasury securities.

At December 31, 2008, our open commodity derivative instruments were in a net receivable position with a fair value of $445 million. We have all of our commodity derivative instruments with major financial institutions. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss.

We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of these parties 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 from our largest international crude oil purchaser; however, we do not have all of our trade credit enhanced 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, L.P., a crude oil purchaser, and recognized a pre-tax charge of $38 million for a probable loss. See Item 8. Financial Statements and Supplementary Data– Note 17 – Commitments and Contingencies.

Crude oil and natural gas prices are also volatile as evidenced by the significant decline during 2008 and into 2009. Continued lower commodity prices will reduce our cash flows from operations. To mitigate the impact of lower commodity prices on our cash flows, we have entered into crude oil and natural gas commodity contracts for 2009 and, to a lesser extent, 2010. See Item 8. Financial Statements and Supplementary Data—Note 6 – Derivative Instruments and Hedging Activities. Depending on the length of the current recession, commodity prices may stay depressed or decline further, thereby causing a prolonged downturn, which would further reduce our cash flows from operations. This could cause us to alter our business plans including reducing or delaying our exploration and development program spending and other cost reduction initiatives.

In addition, the following events impacted our business in 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 oil and gas properties and other investments. As a result of this analysis we determined that certain of our assets were impaired. In addition, during third quarter 2008, we initiated a process to sell our remaining operated non-core Gulf of Mexico shelf asset at Main Pass and recorded an impairment loss (based on anticipated proceeds less costs to sell). For 2008, total pre-tax (non-cash) asset impairment charges totaled $294 million. See Critical Accounting Policies – Impairment of Proved Oil and Gas Properties and Other Investments, and Impairment of Unproved Oil and Gas Properties. See also Item 8. Financial Statements and Supplementary Data—Note 3– Asset Impairments and Note 4 –Acquisitions and Divestitures–Main Pass Asset.

Hurricanes Gustav and Ike – In September, Hurricanes Gustav and Ike moved through the Gulf of Mexico. Inspection of our facilities and equipment indicated there was no major damage from the hurricanes, although damage to third party processing and pipeline facilities has slowed reinstatement of production from our Gulf of Mexico assets, including Lorien and Ticonderoga. Temporary shut-ins of production reduced volumes on average 7.2 MBoepd during third quarter 2008 and 9.0 MBoepd during fourth quarter 2008. Approximately 8.5 MBoepd of our Gulf of Mexico production remained shut-in at December 31, 2008. We expect production to resume during the first half of 2009, pending the successful resumption of pipeline and other non-operated facilities.

Mid-continent Acquisition – In July 2008, we acquired producing properties in western Oklahoma for $292 million in cash. Properties acquired cover approximately 15,500 net acres and are currently producing a net 20 MMcfepd with approximately 70% natural gas and 30% liquids. We operate the assets with an average working interest of 83%.

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 is subject to Argentine government approval, which has not been received. Accordingly, the gain on sale of approximately $24 million has been deferred. We are currently unable to predict when government approval will be obtained.

2009 OUTLOOK

We expect the mid-point of our 2009 crude oil, natural gas and NGL production to be slightly above our 2008 results. The expected year-over-year change in production is impacted by several factors including:

- the amount of development capital expenditures;
- higher sales of natural gas from the Alba field in Equatorial Guinea;
- growth in demand for natural gas in Israel; and
- growing production from our Rocky Mountains assets, where we are continuing an active drilling program;

offset by

- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-continent areas of our US operations.

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Factors potentially impacting our expected production profile include:

- overall level and timing of capital expenditures, as discussed below, which, dependent upon our drilling success, are expected to result in near-term production growth;
- potential hurricane-related volume curtailments in the Gulf of Mexico and Gulf Coast areas of our US operations as occurred with Hurricanes Gustav and Ike;
- the restoration of pipeline and facilities necessary to increase our Gulf of Mexico production;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountains area of our US operations and timing of start up of a new interstate crude oil transportation pipeline system which will run from Weld County, Colorado to Cushing, Oklahoma;
- deliveries of Egyptian gas in Israel, which could lower our sales volumes;
- potential downtime at the methanol, LPG and/or LNG plants in Equatorial Guinea;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project; and
- timing of significant project completion and initial production.

2009 Budget—Due to the uncertain economic and commodity price environment, we have designed a flexible capital spending program that will be responsive to conditions that develop during 2009. Our preliminary base capital program for 2009 will accommodate an investment level similar to our original 2008 program which was $1.6 billion. However, depending on commodity prices and other economic conditions we experience in the first half of 2009, this base capital program may be adjusted up or down by approximately 10% to 15%.

Approximately 40% of the 2009 budget is committed to longer-term projects that will provide considerable production growth several years in the future. The remainder is allocated toward maintaining and strengthening the existing property base. Development spending will focus on our international and deepwater Gulf of Mexico assets as well as certain higher return opportunities onshore in the US. The exploration budget will center on significant resource potential in Israel, West Africa and the deepwater Gulf of Mexico. International expenditures are estimated to represent 30% of the total capital program.

The 2009 budget does not include the impact of possible asset purchases. We expect that the 2009 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.

RESULTS OF OPERATIONS

Net Income

Net income for 2008 was $1.4 billion, a 43% increase over 2007. Factors contributing to the increase in net income included the following:

- $629 million, or 19%, increase in total revenues, due primarily to higher commodity prices; and
- $440 million gain on derivative instruments;

offset by:

- $294 million impairment of assets;
- $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.

Net income for 2007 was $944 million, a 39% increase over 2006. Factors contributing to the increase in net income from 2006 to 2007 included the following:

- $332 million, or 11%, increase in total revenues, due primarily to higher average realized commodity prices and an increase in income from equity method investees; and
- $394 million decrease in loss on derivative instruments;

offset by:

- $208 million decrease in gains from asset sales;
- $103 million increase in DD&A expense;
- $51 million loss on involuntary conversion expense; and
- $51 million increase in oil and gas exploration expense.

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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 provide greater flexibility in our use of derivative instruments. 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.

Net income for 2008 included a $440 million gain on commodity derivative instruments, of which $82 million was a pre-tax realized loss, and $522 million was a pre-tax, unrealized, non-cash gain 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.

Oil, Gas and NGL Sales

Revenues from sales of commodities were as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Crude oil and condensate sales	$ 2,101	$ 1,694	$ 1,489
Natural gas sales	1,375	1,272	1,212
NGL sales (1)	175	-	-
Total	$ 3,651	$ 2,966	$ 2,701

(1) For 2007 and 2006, US NGL sales volumes were included with natural gas volumes. Effective in 2008, we began reporting US NGLs separately, which has lowered the comparative natural gas sales revenues from 2007 to 2008.

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

	Sales Volumes			Average Realized Sales Prices		
	Crude Oil & Condensate (MBopd)	Natural Gas (1) (MMcfpd)	NGLs (1) (MBpd)	Crude Oil & Condensate (Per Bbl)	Natural Gas (1) (Per Mcf)	NGLs (1) (Per Bbl)
Year Ended December 31, 2008						
United States (2)	40	395	9	$ 75.53	$ 8.12	$ 50.15
West Africa (3)	15	206	-	88.95	0.27	-
North Sea	10	5	-	100.56	10.54	-
Israel	-	139	-	-	3.10	-
Ecuador (4)	-	22	-	-	-	-
Other International	4	-	-	82.66	-	-
Total Consolidated Operations	69	767	9	82.60	5.04	50.15
Equity Investees (5)	2	-	6	96.77	-	58.81
Total	71	767	15	$ 82.96	$ 5.04	$ 53.45
Year Ended December 31, 2007						
United States (2)	42	412	-	$ 53.22	$ 7.51	$ -
West Africa (3)	15	132	-	71.27	0.29	-
North Sea	13	6	-	76.47	6.54	-
Israel	-	111	-	-	2.79	-
Ecuador (4)	-	26	-	-	-	-
Other International	7	-	-	53.69	-	-
Total Consolidated Operations	77	687	-	60.61	5.26	-
Equity Investees (5)	2	-	6	74.87	-	48.87
Total	79	687	6	$ 60.94	$ 5.26	$ 48.87
Year Ended December 31, 2006						
United States (2)	46	452	-	$ 50.68	$ 6.61	$ -
West Africa (3)	18	45	-	62.51	0.37	-
North Sea	4	8	-	67.43	8.00	-
Israel	-	93	-	-	2.72	-
Ecuador (4)	-	25	-	-	-	-
Other International	7	-	-	52.05	-	-
Total Consolidated Operations	75	623	-	54.47	5.55	-
Equity Investees (5)	2	-	6	66.60	-	40.10
Total	77	623	6	$ 54.75	$ 5.55	$ 40.10

(1) For 2007 and 2006, US NGL sales volumes were included with natural gas volumes. Effective in 2008, we began reporting US NGLs separately, which has lowered the comparative natural gas sales volumes from 2007 to 2008.

(2) Average realized crude oil and condensate prices reflect reductions of $22.06 per Bbl for 2008, $13.68 per Bbl for 2007, and $11.41 per Bbl for 2006 from hedging activities. Average realized natural gas prices reflect increases of $0.23 per Mcf for 2008 and $1.12 per Mcf for 2007, and a reduction of $0.25 per Mcf for 2006 from hedging activities. 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 $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. We did not hedge West Africa crude oil sales in 2006. 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. Natural gas volumes sold to the LNG plant totaled 163 MMcfpd in 2008 and 78 MMcfpd in 2007. The natural gas sold to the LNG and methanol plants has a lower Btu content than the natural gas sold to the LPG plant. As a result of the increase in natural gas volumes sold to the LNG plant to 2008, the average price received on an Mcf basis is lower.

(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 below.

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

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Crude oil and condensate sales volumes in the table above may differ from actual production volumes due to the timing of liquid hydrocarbon tanker liftings. Crude oil and condensate production volumes were as follows:

	Year Ended December 31,		
	2008	2007	2006
		(MBopd)	
United States	40	42	46
West Africa	14	15	17
North Sea	10	13	4
Other International	4	7	8
Total Consolidated Operations	68	77	75
Equity Investees	2	2	2
Total	70	79	77

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

	Year Ended December 31,2008 (1)	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
United States	$ 71.68	$ 8.05
West Africa	85.98	0.27
Total Consolidated Operations	79.75	5.00
Total	80.19	5.00

(1) In 2007 and 2006 we applied cash flow hedge accounting.

Crude Oil and Condensate Sales

2008 Compared with 2007 —Crude oil sales increased 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 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 Mountains area of our US operations.

Internationally, West Africa crude oil sales increased $88 million due to higher average realized prices. North Sea crude oil sales increased $39 million due to higher average realized prices, while sales volumes were affected by natural field decline. Other international crude oil sales decreased $6 million primarily due to natural field decline in China.

Fourth quarter 2008 crude oil sales were significantly impacted by declining prices. Our average realized crude oil prices were $33.16 per Bbl for the US and $43.80 per Bbl for total consolidated operations for fourth quarter 2008.

2007 Compared with 2006—Crude oil sales increased a net $205 million, or 14%, in 2007 as compared with 2006. The increase was affected by both volume and price changes. In the US, crude oil sales declined by $25 million from the previous year. Deepwater Gulf of Mexico volumes were lower due to well performance, third-party facility restrictions and storm-related shut-ins. The Gulf Coast onshore area had lower production due to natural field decline, and a loss of production from the sale of our significant Gulf of Mexico shelf properties in 2006. Northern region production was negatively impacted by severe winter weather in the Rocky Mountains in the first and fourth quarters of 2007. However, development activity in the Wattenberg field, as well as a full year of production from U.S. Exploration properties acquired in 2006, resulted in increased production in our Northern region. The overall US volume decline was partially offset by higher average realized prices.

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Internationally, West Africa crude oil sales declined by $15 million from the previous year. Volumes declined due to increased downtime and lower condensate yields in Equatorial Guinea, but the decline was offset by substantially higher average realized crude oil prices. In January 2007, production began at the Dumbarton development in the North Sea, and, as a result, crude oil production was more than triple that of the prior year. North Sea crude oil sales increased $257 million over 2006 due to the increased volumes and, to a lesser extent, higher average realized prices. Other international crude oil sales declined $12 million. China experienced lower volumes due to facility downtime and natural field decline.

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 $365 million in 2008, $223 million in 2007, and $191 million in 2006. See Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

Natural Gas Sales

2008 Compared with 2007—Natural gas sales increased 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 $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 Gulf of Mexico from Hurricanes Gustav and Ike, reduction for shrink gas associated with the natural gas liquids now 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 Mountains area of our US operations.

Internationally, West Africa gas sales increased $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 the North Sea, sales increased $6 million primarily due to higher average realized prices. In Israel, natural gas sales increased $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.

Fourth quarter 2008 natural gas sales were significantly impacted by declining prices. Our average realized natural gas prices were $5.30 per Mcf for the US and $3.62 per Mcf for total consolidated operations for fourth quarter 2008.

2007 Compared with 2006—Natural gas sales increased a net $60 million, or 5%, in 2007 as compared with 2006. The increase was affected by both volume and price changes. In the US, natural gas sales increased $40 million from the previous year despite lower sales volumes. Deepwater Gulf of Mexico volumes were slightly higher than 2006, while development activity in the Piceance basin and a full year of production from U.S. Exploration properties acquired in 2006 resulted in increased production in the Northern region. However, the Gulf Coast onshore area had lower production due to natural field decline, and there was a loss of production due to the sale of our significant Gulf of Mexico shelf properties in 2006. The Northern region also experienced a temporary decline in production due to third party processing downtime and inclement weather. The net production decrease was more than offset by a 14% increase in average realized natural gas prices.

Internationally, West Africa natural gas sales increased $8 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 the North Sea, natural gas production decreased 23% as compared with the prior year primarily due to natural field decline. Lower production, combined with lower average realized prices, resulted in a $9 million decrease in North Sea natural gas sales. In Israel, natural gas sales increased $21 million due to record sales volumes. There was a full year of sales to the IEC Reading power plant in Tel Aviv, as well as the start up of sales to a desalinization plant and a paper mill.

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, and a decrease of $41 million in 2006. See Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

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NGL Sales

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,		
	2008	2007	2006
Net income	(in millions, except as noted)		
AMPCO and affiliates	$ 56	$ 83	$ 38
Alba Plant	118	128	101
Distributions/dividends			
AMPCO and affiliates	65	97	37
Alba Plant	156	132	151
Sales volumes			
Methanol (MMgal) (1)	119	161	110
Condensate (MBopd)	2	2	2
LPG (MBpd)	6	6	6
Production volumes			
Methanol (MMgal) (1)	116	163	109
Condensate (MBopd)	2	2	2
LPG (MBpd)	6	6	6
Average realized prices			
Methanol (per gallon)	$ 1.25	$ 1.09	$ 0.90
Condensate (per Bbl)	96.77	74.87	66.60
LPG (per Bbl)	58.81	48.87	40.10

(1) The variance between methanol production and sales volumes is attributable to management's decision to increase or decrease inventory.

AMPCO and Affiliates — Net income from AMPCO and affiliates decreased $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.

Net income from AMPCO and affiliates increased substantially in 2007 as compared with 2006 due to increases in methanol sales volumes and average realized methanol prices. The increase in methanol sales volumes was due to a 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006 followed by 35 days of compressor repairs.

Alba Plant—Net income from Alba Plant decreased $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. Net income from Alba Plant increased $27 million, or 27%, in 2007 as compared with 2006 due to increases in average realized condensate and LPG prices.

Our operating cash flows include dividends received from Alba Plant of $156 million in 2008 and $132 million in 2007. In 2006, distributions received from Alba Plant were classified within investing cash flows as a repayment of a loan. The change in classification was the result of all outstanding loans being repaid to us by Alba Plant in December 2006.

Other Revenues

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

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Costs and Expenses

Production Costs—Production costs were as follows:

	Total	United States	West Africa	North Sea	Israel	Other Int'l/ Corporate (1)
			(in millions)			
Year Ended December 31, 2008						
Oil and gas operating costs (2)	$ 333	$ 222	$ 39	$ 50	$ 9	$ 13
Workover and repair expense	38	35	-	3	-	-
Lease operating expense	371	257	39	53	9	13
Production and ad valorem taxes	166	135	-	-	-	31
Transportation expense	57	49	-	7	-	1
Total production costs	$ 594	$ 441	$ 39	$ 60	$ 9	$ 45
Year Ended December 31, 2007						
Oil and gas operating costs (2)	$ 299	$ 190	$ 39	$ 38	$ 8	$ 24
Workover and repair expense	23	23	-	-	-	-
Lease operating expense	322	213	39	38	8	24
Production and ad valorem taxes	114	91	-		-	23
Transportation expense	52	40	-	11	-	1
Total production costs	$ 488	$ 344	$ 39	$ 49	$ 8	$ 48
Year Ended December 31, 2006						
Oil and gas operating costs (2)	$ 270	$ 205	$ 27	$ 12	$ 9	$ 17
Workover and repair expense	47	47	-	-	-	-
Lease operating expense	317	252	27	12	9	17
Production and ad valorem taxes	109	86	-	-	-	23
Transportation expense	29	21	-	7	-	1
Total production costs	$ 455	$ 359	$ 27	$ 19	$ 9	$ 41

(1) Other international includes Ecuador, China and Argentina (through February 2008).
(2) Oil and gas operating costs include labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs and exclude depreciation of support equipment and facilities such as vehicles.

Oil and gas operating costs increased $34 million, or 11%, in 2008 as compared with 2007. The increase is primarily the result of higher costs related to the continuing active drilling program in the Rocky Mountains and Mid-continent areas of our US operations. North Sea oil and gas operating costs increased due to expanded operations and higher costs at the Dumbarton development.

Oil and gas operating costs increased $29 million, or 11%, in 2007 as compared with 2006. The increase was primarily the result of expanded operations in Equatorial Guinea and the North Sea.

Workover and repair expense increased $15 million, or 65%, in 2008 as compared with 2007. The increase was primarily due to increased workover activity in the Piceance basin, Wattenberg field, and Mid-continent and Gulf Coast areas of our US operations.

Workover and repair expense decreased $24 million, or 51%, in 2007 as compared with 2006. The decrease was primarily due to a reduction in hurricane-related repair expense, which totaled $30 million in 2006 and $1 million in

2007.

Production and ad valorem tax expense increased $52 million, or 46%, in 2008 as compared with 2007, and increased $5 million, or 5%, in 2007 as compared with 2006. The increases were driven primarily by 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 $5 million, or 10%, in 2008 as compared with 2007. The increase was due primarily to higher natural gas production in the Wattenberg field and increased production from the Swordfish development in the deepwater Gulf of Mexico.

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Transportation expense increased $23 million, or 79%, in 2007 as compared with 2006. The increase was due primarily due to changes in the terms of certain sales contracts for Northern region production and increased production in the North Sea.

Selected expenses on a per BOE of sales volume basis were as follows:

	Year Ended December 31,		
	2008	2007	2006
Oil and gas operating costs	$ 4.39	$ 4.29	$ 4.14
Workover and repair expense	0.51	0.33	0.72
Lease operating costs	4.90	4.62	4.86
Production and ad valorem taxes	2.19	1.63	1.67
Transportation expense	0.75	0.74	0.44
Total production costs (1)	$ 7.84	$ 6.99	$ 6.97

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $1.19 per BOE for 2008 and $0.51 per BOE for 2007.

The unit rates of total production costs per BOE have been increasing year-over-year since 2006. The increases are 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	North Sea	Israel	Other Int'l/ Corporate (1)
			(in millions)			
Year Ended December 31, 2008						
Dry hole expense	$ 84	$ 42	$ 1	$ 8	$ -	$ 33
Seismic	57	50	-	4	3	-
Staff expense	62	14	7	5	1	35
Other	14	13	-	1	-	-
Total exploration expense	$ 217	$ 119	$ 8	$ 18	$ 4	$ 68
Year Ended December 31, 2007						
Dry hole expense	$ 90	$ 50	$ 40	$ -	$ -	$ -
Seismic	65	55	1	8	1	-
Staff expense	46	12	2	9	1	22
Other	18	17	-	-	-	1
Total exploration expense	$ 219	$ 134	$ 43	$ 17	$ 2	$ 23
Year Ended December 31, 2006						
Dry hole expense	$ 70	$ 66	$ -	$ 4	$ -	$ -
Seismic	38	29	4	1	-	4
Staff expense	39	13	3	5	-	18
Other	21	20	-	1	-	-
Total exploration expense	$ 168	$ 128	$ 7	$ 11	$ -	$ 22

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

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).

Exploration expense increased $51 million, or 30%, in 2007 as compared with 2006. US dry hole expense decreased $16 million due to a reduction in the number of dry holes drilled in 2007. Dry hole expense increased $40 million in West Africa and included amounts related to a dry exploratory well in Equatorial Guinea and expense related to a secondary target of an exploration well in Cameroon. Seismic expense increased a net $27 million in 2007 as compared with 2006, primarily due to increases in US seismic expense incurred in support of the 2007 central Gulf of Mexico outer continental shelf sale. Staff expense increased a net $7 million primarily due to new venture activity.

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Exploration expense included stock-based compensation expense of $1 million in 2008, $2 million in 2007 and $1 million in 2006.

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

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
United States	$ 646	$ 580	$ 552
West Africa	34	25	24
North Sea	55	81	9
Israel	24	18	14
Other international, corporate, and other	32	32	34
Total DD&A expense (1)	$ 791	$ 736	$ 633
Unit rate of DD&A per BOE (2)	$ 10.44	$ 10.55	$ 9.71

(1) DD&A expense includes accretion of discount on asset retirement obligations of $10 million in 2008, $8 million in 2007, and $11 million in 2006.
(2) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $1.29 per BOE for 2008 and $0.63 per BOE for 2007.

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 Rocky Mountain and Mid-continent areas in the US, negative year-end reserve 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.

Total DD&A expense increased in 2007 as compared with 2006 primarily due to higher crude oil sales volumes in the North Sea due to start-up of the Dumbarton development, higher natural gas sales volumes in Israel and West Africa and higher acquisition and/or development costs in the North Sea and in the Wattenberg field and deepwater Gulf of Mexico in the US.

The decrease in the unit rate for 2008 as compared with 2007 is 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 (the Wattenberg field and other Rocky Mountain and Mid-continent areas in the US) and negative year-end reserve revisions in the US due to lower commodity prices.

The increase in the unit rate for 2007 as compared with 2006 was primarily due to higher acquisition and development costs in the US and the North Sea Dumbarton development.

DD&A expense includes abandoned assets cost of $5 million in 2007 and $1 million in 2006. There was no abandoned asset cost in 2008.

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

	Year Ended December 31,		
	2008	2007	2006

G&A expense (in millions)	$	236	$	206	$	165
Unit rate per BOE (1)	$	3.12	$	2.96	$	2.52

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. Sales volumes include natural gas sales to an LNG plant in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.47 per BOE for 2008 and $0.21 per BOE for 2007.

G&A expense increased $30 million, or 15%, in 2008 as compared with 2007. Our increased activities require additional personnel, which has resulted in higher payroll costs. We have also increased our incentive compensation accruals.

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G&A expense increased $41 million, or 25%, in 2007 as compared with 2006 due to higher salaries and wages, including incentive compensation programs, resulting from an increase in the number of employees and results exceeding targeted performance goals.

In addition, the amount of stock-based compensation expense included in G&A has been increasing since the adoption of SFAS No. 123(R), "Share-Based Payment" in 2006 combined with additional equity-based awards. Stock-based compensation expense included in G&A totaled $38 million in 2008, $25 million in 2007 and $11 million in 2006.

G&A also includes actuarially-computed net periodic benefit cost related to pension and other postretirement benefit plans of $17 million in 2008, $17 million in 2007, and $19 million in 2006.

Impairment of Assets—During 2008, we recorded total pre-tax (non-cash) impairment charges of $294 million primarily due to lower commodity prices at year-end. We recorded impairments of $4 million in 2007 and $9 million in 2006, primarily related to downward reserve revisions on proved US oil and gas properties and/or adjustment of the carrying value of properties to their fair values. See Critical Accounting Policies – Impairment of Proved Oil and Gas Properties and Other Investments and Impairment of Unproved Oil and Gas Properties; and Item 8. Financial Statements – Note 3 – Asset Impairments.

Gain on Sale of Assets—See Item 8. Financial Statements and Supplementary Data—Note 4—Acquisitions and Divestitures.

Other Operating Expense, Net – Other operating expense, net includes electricity generation expense, gathering, marketing and processing expense, loss on involuntary conversion of assets and other operating (income) expense, net. See Electricity Sales and Loss on Involuntary Conversion below. See also Item 8. Financial Statements – Note 2 – Summary of Significant Accounting Policies and Note 17 – Commitments and Contingencies - Purchaser Bankruptcy for a discussion of the SemCrude matter.

Electricity Sales—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,		
	2008	2007	2006
	(in millions, except as noted)		
Electricity sales	$ 56	$ 71	$ 72
Electricity generation expense	57	57	59
Operating income	(1)	14	13
Power generation (GW)	749	912	866
Average power price ($/Kwh)	$ 0.074	$ 0.078	$ 0.083

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 DD&A expense and changes in the allowance for doubtful accounts of $11 million in 2008, $14 million in 2007, and $15 million in 2006. Through December 31, 2008, we recorded an allowance for doubtful accounts of $57 million. The allowance was 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. As a result of pursuing various strategies to protect our interests, including international arbitration and litigation, we reached a settlement in fourth quarter 2008. However, we have not yet received any funds related to the settlement. We will reverse our allowance for doubtful accounts upon receipt of payment from the Ecuadorian government. If not received in the near term, we may continue pursuing our arbitration claim and litigation.

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 Ecuador investment. As a result of this analysis we determined that our investment was impaired and recorded a pre-tax (non-cash) impairment of $70 million. See Critical Accounting Policies – Impairment of Proved Oil and Gas Properties and Other Investments and Item 8. Financial Statements – Note 3 – Asset Impairments.

Loss on Involuntary Conversion— 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.

(Gain) Loss on Commodity Derivative Instruments— We recorded a gain of $440 million in 2008, a gain of $2 million in 2007, and a loss of $392 million in 2006 related to commodity derivative instruments. See Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

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

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Interest expense	$ 102	$ 130	$ 130
Capitalized interest	(33)	(17)	(13)
Interest expense, net	$ 69	$ 113	$ 117

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.

Interest expense was flat in 2007 as compared with 2006. The rate of interest applicable to the credit facility declined from 5.69% at December 31, 2006 to 5.28% at December 31, 2007, while the balance outstanding increased slightly.

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 and deepwater Gulf of Mexico and numerous projects in the Rocky Mountains area in 2008; West Africa, the North Sea and deepwater Gulf of Mexico in 2007; and the North Sea and deepwater Gulf of Mexico in 2006. See Item 8. Financial Statements and Supplementary Data—Note 7 – Exploratory Well Costs.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. At December 31, 2008, AOCL included a deferred loss of $3 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 (Income) Expense, net— Other (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense, net. See Deferred Compensation (Income) Expense below. See also Item 8. Financial Statements – Note 2 – Summary of Significant Accounting Policies.

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, 2008, approximately 42% of the market value of the assets in the rabbi trust related to our common stock. Increases in the market value of our common stock held in the trust result in the recognition of deferred compensation expense. Decreases in the market value of our common stock held in the trust result in the recognition of deferred compensation income. We recognized deferred compensation income of $32 million in 2008 and deferred compensation expense of

$33 million in 2007 and $16 million in 2006. The amounts are included in other (income) expense, net in the consolidated statements of operations. See Item 8. Financial Statements and Supplementary Data— Note 2 – Summary of Significant Accounting Policies and Note 12—Benefit Plans.

Income Tax Provision—The income tax provision was as follows:

	Year Ended December 31,		
	2008	2007	2006
Income tax provision (in millions)	$ 711	$ 424	$ 418
Effective rate	34.5%	31.0%	38.1%

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 Liquidity and Capital Resources–Overview – Cash and Cash Equivalents below.

Several factors resulted in a decrease in our effective tax rate for 2007 as compared with 2006. The major factor was that, in 2006, $100 million of goodwill write-off associated with the sale of Gulf of Mexico shelf properties was not deductible, which increased the rate for 2006. Other factors were an increase in deferred tax assets arising from foreign tax credits, a decrease in the Chinese tax rate, and the realization of additional income from equity method investees which is a favorable permanent difference in calculating the income tax expense.

In addition to the nondeductible goodwill write-off of $100 million related to the sale of Gulf of Mexico shelf properties discussed in the preceding paragraph, the 2006 effective tax rate was impacted by decreases in our US deferred tax assets arising from future foreign tax credits due to changes in the limitation on our ability to claim foreign tax credits. In addition, a change in UK tax law increased our UK tax expense in 2006 as compared with 2005. Offsetting these increases was a reduction in the effective tax rate due to an increase in earnings from equity method investees, which is a favorable permanent difference in calculating income tax expense. See Item 8. Financial Statements – Note 9 —Income Taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary cash needs are to fund operating expenses and capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings and associated interest payments and other contractual commitments and to pay dividends. Traditional sources of liquidity are cash on hand, cash flows from operations and available borrowing capacity under credit facilities. Occasional sales of non-strategic crude oil and natural gas properties may also generate cash.

The recent disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed 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, further deterioration in the credit markets 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 $1.1 billion in cash and cash equivalents at December 31, 2008, compared with $660 million at December 31, 2007. Our cash is denominated in US dollars and is invested in highly liquid, investment-grade securities with original maturities of three months or less at the time of purchase. 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 West Africa.

During 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 believe it is likely that repatriation of a portion of the accumulated earnings of foreign subsidiaries will occur during 2009. Therefore, at December 31, 2008, we recorded deferred taxes on the portion of those earnings that we expect will be repatriated. The recognition of deferred tax liabilities resulted in $9 million additional income tax expense reported in continuing operations.

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. Such instruments include variable to fixed commodity price swaps, costless collars and basis swaps.

As of December 31, 2008, we had commodity derivative assets totaling $470 million and commodity derivative liabilities totaling $25 million (after consideration of netting agreements). Our hedging arrangements are currently with a diversified group of 11 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 Hedging transactions, receivables and cash investments expose us to counterparty credit risk.

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 by our marketing subsidiary, none of our counterparty agreements contain margin requirements. See additional information included in Critical Accounting Policies – Commodity Derivative Instruments and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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Certain of our commodity contracts were executed in connection with the Patina Merger, prior to the global crude oil and natural gas price escalations which began in early 2005. The settlements of these contracts have reduced our cash flows. However, these contracts expired in December 2008. Our remaining commodity contracts were executed in more favorable price environments. Although we cannot predict market prices, our remaining commodity contract positions should result in more favorable cash flows as compared to our commodity contract positions in prior periods. See Item 8. Financial Statements and Supplementary Data – Note 6 – Derivative Instruments and Hedging Activities for our current hedge positions.

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2008	2007	2006
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 2,285	$ 2,017	$ 1,730
Investing activities	(2,132)	(1,403)	(1,098)
Financing activities	327	(107)	(589)
Increase in cash and cash equivalents	$ 480	$ 507	$ 43

Operating Activities—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.

Net cash provided by operating activities was $2.0 billion in 2007, an increase of $287 million, or 17% as compared with 2006. The increase was due primarily to increased sales resulting from higher average realized crude oil prices and higher average realized US natural gas prices. These increases were partially offset by higher exploration expense and G&A expense. In addition, cash flows from operating activities in 2007 included dividends from equity method investees. Cash distributions from equity method investees received in 2006 were repayments of loans and were included in investing activities. See Results of Operations—Income 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 or distributions from equity method investees. 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 acquisition, development and exploratory 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, we had additions to property, plant and equipment ($1.4 billion) primarily due to development activity in the US and North Sea and acquisition and exploratory activities in the US and West Africa. Expenditures were minimally offset by proceeds from property sales of $9 million.

In comparison, in 2006 cash flows from investing activities totaled $1.1 billion. We had acquisitions and additions to property, plant and equipment ($1.8 billion) due to the acquisition of U.S. Exploration plus additional development and exploratory activity in the US and development activity in the North Sea. These expenditures were offset by proceeds from the sale of our significant Gulf of Mexico shelf properties ($520 million) and net distributions received from equity method investees ($151 million). The distributions from equity method investees were the result of repayment of loans and therefore were included in cash flows from investing activities. See Results of Operations—Income from Equity Method Investees.

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Financing Activities—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 our expanded capital budget, noted above, which included significant domestic acquisition, development and exploration activities and as well as 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 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. Our capital expenditures, noted above, were somewhat reduced from that of 2006 resulting in a need for borrowings of only a net $25 million. Funds were also provided by the 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 common stock ($75 million).

In 2006, we used cash of $589 million in financing activities. We used excess cash to reduce borrowings by a net $230 million, repurchase eight million shares of our common stock ($399 million), and pay cash dividends on common stock ($49 million). Funds were also provided by the cash proceeds from, and tax benefits related to, the exercise of stock options ($89 million).

Acquisition, Capital and Other Exploration Expenditures

Expenditure information (on an accrual basis) is as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Acquisition, Capital and Other Exploration Expenditures			
Unproved property acquisition (1)	$ 303	$ 145	$ 185
Proved property acquisition (2)	255	11	523
Exploration expenditures	448	372	203
Development expenditures	1,193	1,175	1,055
Corporate and other expenditures	65	36	35
Total expenditures	2,264	1,739	2,001

(1) Unproved property acquisition cost for 2008 includes $179 million for deepwater Gulf of Mexico lease blocks, $38 million related to the Mid-continent acquisition, $80 million related to additional onshore US lease acquisitions and $6 million related to international lease acquisitions. Unproved property acquisition cost for 2006 includes $131 million allocated to properties acquired in the U.S. Exploration acquisition.

(2) Proved property acquisition cost for 2008 includes $254 million related to the Mid-continent acquisition. Proved property acquisition cost for 2006 includes $413 million allocated to properties acquired in the U.S. Exploration acquisition.

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

Total expenditures in 2007 decreased $262 million, or 13%, as compared with 2006. The decrease was due to significantly lower acquisition expenditures, offset by exploratory activities in West Africa and the North Sea, and increased development activity in the Northern region and Gulf of Mexico area of our US operations.

Insurance Recoveries

Our corporate insurance program provides up to $260 million property damage coverage per loss event. However, our insurance carrier's aggregation limit for catastrophic windstorm events is $750 million. If an insured catastrophic loss event occurs, we could still recover less than our stated limits should the total aggregate losses realized by our carrier exceed its $750 million aggregation limit that is applicable to any single loss event.

We carry additional property damage and control of well coverage for our deepwater Gulf of Mexico and remaining Gulf of Mexico shelf properties. This additional insurance provides up to $100 million in additional coverage for certain claims which exceed the $260 million property damage coverage or where the $260 million property damage coverage is reduced by application of the $750 million aggregation limit. We carry business interruption insurance for certain international locations.

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Financing Activities

Long-Term Debt—Our long-term debt totaled $2.245 billion (excluding unamortized discount) at December 31, 2008, and maturities range 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, 2008, $1.606 billion in borrowings were outstanding under the credit facility, leaving $494 million available for use. The weighted average interest rate applicable to borrowings under the credit facility at December 31, 2008 was 0.80%.

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.

The credit facility is with certain commercial lending institutions and is available for general corporate purposes. Our bank group is comprised of 24 commercial lending institutions, each holding between 1.0% and 7.0% 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.

We also have $639 million of fixed-rate debt outstanding at December 31, 2008 with a weighted average interest rate of 6.92%. Maturities range from 2014 to 2097.

Short-Term Borrowings— We owe $25 million in the form of an installment payment to the seller of properties we purchased in 2007. The amount is due May 11, 2009 and is included in short-term borrowings in the consolidated balance sheets. Interest on the unpaid amount is due quarterly and accrues at a LIBOR rate plus .30%. The interest rate was 4.18% at December 31, 2008.

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, 2008 or 2007. 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 has decreased from 28% at December 31, 2007 to 26% at December 31, 2008. 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. Significant changes in our financial position causing a change in the ratio of debt-to-book capital included the following:

- $1.4 billion increase in shareholders' equity from current year net income;

offset by

- $390 million increase in total debt from the balance at December 31, 2007; and
- $115 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.

Cash Interest Payments—We made cash interest payments of $109 million in 2008, $122 million in 2007 and $119 million in 2006.

Exercise of Stock Options—Proceeds from the exercise of stock options totaled $27 million in 2008, $25 million in 2007 and $63 million in 2006. 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 66.0 cents per common share in 2008, 43.5 cents per common share in 2007 and 27.5 cents per common share in 2006. On January 27, 2009, the Board of Directors declared a quarterly cash dividend of $0.18 cents per common share, which will be paid February 23, 2009 to shareholders of record on February 9, 2009. 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.

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Common Stock Repurchases—In 2008, we received from employees approximately 33,000 shares of common stock with a total value of $3 million for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. In 2007, we completed a common stock repurchase program authorized by our Board of Directors in 2006. We repurchased two million shares of our common stock at an aggregate cost of $102 million in 2007 and 8.4 million shares of our common stock at an aggregate cost of $399 million in 2006, resulting in a total of 10.4 million shares acquired at an average price of $48.17 per share.

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, 2008, 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. 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.

	Payments Due by Period				
	Total	2009	2010 and 2011	2012 and 2013	2014 and Beyond
			(in millions)		
Long-term debt (excluding interest) (1)	$ 2,270	$ 25	$ -	$ 1,606	$ 639
Drilling and equipment obligations: (2)					
United States	752	70	613	69	-
International	480	252	225	3	-
Purchase obligations (3)	163	163	-	-	-
Throughput agreement (4)	95	14	38	38	5
Transportation and gathering (5)	43	12	17	10	4
Operating lease obligations (6)	56	12	18	8	18
Other long-term liabilities: (7)					
Asset retirement obligations (8)	211	27	18	29	137
Commodity derivative instruments (9)	25	23	2	-	-
Total contractual obligations	$ 4,095	$ 598	$ 931	$ 1,763	$ 803

(1) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2008, our cash payments for interest would be $58 million in 2009, $57 million in 2010, $57 million in 2011, $56 million in 2012, $44 million in 2013 and $878 million for the remaining years for a total of $1.2 billion. See Item 8. Financial Statements and Supplementary Data—Note 8—Debt.

(2) 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.

(3) 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.

(4) 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 is expected to become operational in 2009. See Item 8. Financial Statements and Supplementary Data—Note 17—Commitments and Contingencies.

(5) Transportation and gathering obligations represent minimum changes for our firm transportation and gathering agreements. See Item 8. Financial Statements and Supplementary Data —Note 17—Commitments and Contingencies.

(6) 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.

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(7) The table excludes deferred compensation liabilities of $159 million and accrued benefit costs of $81 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data—Note 12—Benefit Plans.
(8) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data—Note 10—Asset Retirement Obligations.
(9) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2008. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2008. See Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

We accrued approximately $20 million as of December 31, 2008, for an insurance contingency due to our membership in Oil Insurance Limited (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 $5 million at December 31, 2008.

Other

Contributions to Pension and Other Postretirement Benefit Plans—We made contributions to the pension and other postretirement benefit plans totaling $38 million in 2008, $12 million in 2007, and $36 million in 2006. The actual return on plan assets was a loss of $43 million in 2008 and a gain of $13 million in 2007. 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 2009. However, we may make additional contributions to our pension plan. In 2009, we expect to make contributions pertaining to the restoration and medical and life plans of approximately $3 million, 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 $263 million in 2008, $149 million in 2007, and $115 million in 2006.

Contingencies—We paid a total of approximately $2 million to settle legal proceedings in 2008 and $56 million to settle legal proceedings in 2007. These amounts had been accrued previously. During 2006, no significant payments were made to settle any legal proceedings. 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 reserve 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. 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 reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Estimates of proved crude oil and natural gas reserves significantly affect our DD&A expense.

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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.

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, 2008, the balance of property, plant and equipment included $501 million of suspended exploratory well costs, $245 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 wells, or evaluating the potential of the exploration wells. For more information, 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 an 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 reserve 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.

We assessed the recoverability of our proved oil and gas properties and other investments at December 31, 2008. As a result of this analysis, we determined that certain of our assets were impaired. In addition, during third quarter 2008, we recorded an impairment charge related to an asset held for sale. For 2008 total pre-tax (non-cash) asset impairment charges, assessed under SFAS 144, were approximately $219 million of which $149 million is related to our US proved properties and $70 million related to our investment in Ecuador. These assets were written down to their estimated fair values under a discounted cash flows model. The discounted cash flows model included management's estimates of future oil and gas production; commodity prices based on December 31, 2008 commodity price strips; operating and development costs, as well as appropriate discount rates. See Item 8. Financial Statements and Supplementary Data—Note 3—Asset Impairments. We recorded approximately $4 million of impairments in 2007 and $9 million in 2006, primarily related to downward reserve revisions on US properties and/or adjustment of the carrying value of properties to their fair values.

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 adjacent leaseholds, our geologists' evaluation of the lease, and the remaining months in the lease term.

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, future commodity prices and future costs to extract the reserves. Downward revisions in estimated reserve 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 price curves for the related commodities, 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, 2008. Due to the decrease in commodity prices, we recorded a pre-tax (non-cash) impairment charge of $75 million related to our US unproved properties. These impairments were primarily related to allocated fair value attributable to probable and possible reserves acquired in previous business combinations. We assessed these properties under a discounted cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. See Item 8. Financial Statements and Supplementary Data—Note 3—Asset Impairments.   We recorded impairments of significant unproved oil and gas properties of $3 million in 2007 and $1 million in 2006 and reported the amounts in exploration expense.

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 reserve 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 basis 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, reserve quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserve 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, 2008, the consolidated balance sheet included $759 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, appropriate discount rates and other variables. Downward revisions of estimated reserve 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 flows model described above include estimated quantities of oil and gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of future commodity prices based on the December 31, 2008 commodity price strips; 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 9%.

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, 2008, we used a peer company multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics, such as earnings before interest, taxes, DD&A and exploration expense (also known as “EBITDAX”).

Using the range of US reporting unit fair values provided by the income and market approaches as of December 31, 2008, we determined that the fair value of our US reporting unit 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. During 2006, we allocated $100 million of US reporting unit goodwill to the carrying amount of Gulf of Mexico shelf properties sold. 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.

Commodity Derivative Instruments and Hedging Activities—We use various derivative instruments to minimize the impact of commodity price fluctuations on forecasted sales of crude oil and natural gas production. We also use derivative instruments in connection with purchases and sales of third-party production to lock in profits or limit exposure to commodity price risk. 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. We account for derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended", and all derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net receivable position with a fair value of $445 million at December 31, 2008. We estimated the fair values of our commodity derivative instruments in accordance with SFAS 157, "Fair Value Measurements" (SFAS 157), which we adopted as of January 1, 2008. 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 for the underlying commodities 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 costless 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, 2008, we reported a $440 million gain on commodity derivative instruments. See Item 8. Financial Statements and Supplementary Data—Note 6—Derivative Instruments and Hedging Activities.

Asset Retirement Obligation—Our asset retirement obligations (ARO) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. SFAS No. 143, "Accounting for Asset Retirement Obligations," 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. 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 $211 million at

December 31, 2008. 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 during 2007. During 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. 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, 2008, the accumulated undistributed earnings of our foreign subsidiaries on which no US taxes have been recorded totaled approximately \$1.1 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. We currently believe that the repatriation of a portion of our international undistributed earnings is likely. Therefore, as of December 31, 2008, we have recorded additional US deferred income taxes of \$9 million on the portion of undistributed earnings of our foreign subsidiaries that we anticipate will be repatriated. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

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.

The allowance for doubtful accounts totaled $97 million at December 31, 2008. This amount includes a $38 million reduction in the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser. We recognized an associated pre-tax charge of $38 million during third quarter 2008. See Item 8. Financial Statements and Supplementary Data—Note 17 – Commitments and Contingencies.

In addition, 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. However, we have not yet received any funds related to the settlement. We will reverse our allowance for doubtful accounts upon receipt of payment from the Ecuadorian government. 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, 2008, cumulative asset gains (losses) of approximately $3 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 2008 net periodic benefit cost by approximately $2 million. The fair value of plan assets was $132 million at December 31, 2008. The expected return assumption used in the calculation of 2008 net periodic benefit cost was 8.25%. The assumption will be reduced to 8.00% for the calculation of 2009 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, 2008 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 2008 net periodic benefit cost by $2 million and decreased the benefit obligation for the combined plans by $20 million at December 31, 2008. A 1%

decrease in the discount rate assumption would have increased 2008 net periodic benefit cost by $2 million and increased the benefit obligation for the combined plans by $24 million at December 31, 2008. The assumed discount rate used to determine net periodic benefit cost for 2008 was 6.50% for our defined benefit pension and restoration plans and 6.25% for our medical and life plans. The assumed discount rate used to determine the benefit obligations at December 31, 2008 was 6.00% for our defined benefit pension plan and 6.25% for our restoration and medical and life plans. The total accrued benefit obligation for our defined benefit pension, restoration and medical and life plans was $216 million at December 31, 2008.

Recently Issued Pronouncements—See Item 8. Financial Statements and Supplementary Data—Note 18—Recently Issued Pronouncements.

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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, 2008, we had entered into variable to fixed price commodity swaps, costless collars and basis swaps related to crude oil and natural gas sales. Our open commodity derivative instruments were in a net receivable position with a fair value of $445 million. Based on the December 31, 2008 published forward commodity price curves for the underlying commodities, a price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately $9 million. A price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately $7 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, 2008, a net unrealized loss of $48 million, net of tax, is recorded in AOCL in the consolidated balance sheets. We will reclassify $36 million of the deferred loss to earnings during 2009 as adjustments to revenue when the associated production occurs. The remaining $12 million of deferred loss will be reclassified to earnings during 2010.

Interest Rate Risk

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

At December 31, 2008, we had $2.245 billion (excluding unamortized discount) of long-term debt outstanding. Of this amount, $639 million was fixed-rate debt with a weighted average interest rate of 6.92%. 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, $1.606 billion at December 31, 2008, was variable-rate debt. We also had $25 million of short-term variable-rate debt at December 31, 2008. 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, 2008 balance of our variable-rate debt would result in a change in annual interest expense of approximately $4 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, 2008, AOCL included $3 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 short-term investments. As of December 31, 2008, 58% of our cash was invested in US Treasury securities. A hypothetical 25 basis point change in the floating interest rates applicable to the December 31, 2008 balance would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

We have not entered into foreign currency derivative instruments. The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in a foreign currency are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. We do not have any significant monetary assets or liabilities denominated in a foreign currency other than our foreign deferred tax liabilities in certain foreign tax jurisdictions. 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. However, transaction gains or losses were not material in any of the periods presented and we do not believe we are currently exposed to any material risk of loss on this basis. Such gains or losses are included in other (income) expense, net in the consolidated statements of operations.

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Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

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Management's Report on Internal Control over Financial Reporting

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

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

As of December 31, 2008, 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, 2008, 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, 2008 which is included herein.

Noble Energy, Inc.

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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, 2008 and 2007, 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, 2008. 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, 2008 and 2007 was $105.6 million and $142.5 million, respectively, and its equity in earnings of Alba was $118.4 million, $128.1 million and $101.3 million for the years ended December 31, 2008, 2007, and 2006, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective December 31, 2006, the Company changed its method of accounting for defined benefit pension and other postretirement plans.

We also have audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2008, 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, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 18, 2009

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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, 2008, 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, 2008, 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, 2008 and 2007, 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, 2008, and our report dated February 18, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 18, 2009

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

	Year Ended December 31, 2008	2007	2006
Revenues			
Oil, gas and NGL sales	$ 3,651	$ 2,966	$ 2,701
Income from equity method investees	174	211	139
Other revenues	76	95	100
Total	3,901	3,272	2,940
Costs and Expenses			
Lease operating expense	371	322	317
Production and ad valorem taxes	166	114	109
Transportation expense	57	52	29
Exploration expense	217	219	168
Depreciation, depletion and amortization	791	736	633
General and administrative	236	206	165
Asset impairments	294	4	9
Gain on sale of assets	(5)	(12)	(220)
Other operating expense, net	129	145	111
Total	2,256	1,786	1,321
Operating Income	1,645	1,486	1,619
Other (Income) Expense			
(Gain) loss on commodity derivative instruments	(440)	(2)	392
Interest, net of amount capitalized	69	113	117
Other (income) expense, net	(45)	7	14
Total	(416)	118	523
Income Before Income Taxes	2,061	1,368	1,096
Income Tax Provision	711	424	418
Net Income	$ 1,350	$ 944	$ 678
Earnings Per Share			
Basic	$ 7.83	$ 5.52	$ 3.86
Diluted	7.58	5.45	3.79
Weighted average number of shares outstanding			
Basic	173	171	176
Diluted	176	173	179

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

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

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,140	$ 660
Accounts receivable, net	423	594
Commodity derivative instruments	437	15
Deferred income taxes	-	131
Asset held for sale	26	82
Other current assets	132	87
Total current assets	2,158	1,569
Property, plant and equipment:		
Oil and gas properties (successful efforts method of accounting)	11,963	10,217
Other property, plant and equipment	175	112
Total property, plant and equipment, net	12,138	10,329
Accumulated depreciation, depletion and amortization	(3,134)	(2,384)
Total property, plant and equipment, net	9,004	7,945
Goodwill	759	761
Other noncurrent assets	463	556
Total Assets	$ 12,384	$ 10,831
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 579	$ 781
Income taxes payable	130	52
Commodity derivative instruments	23	540
Deferred income taxes	142	-
Other current liabilities	300	263
Total current liabilities	1,174	1,636
Long-term debt	2,241	1,851
Deferred income taxes	2,174	1,984
Other noncurrent liabilities	486	551
Total Liabilities	6,075	6,022
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;		
192 million and 191 million shares issued, respectively	641	636
Capital in excess of par value	2,193	2,106
Accumulated other comprehensive loss	(110)	(284)

Treasury stock, at cost: 19 million shares		(614)		(613)
Retained earnings		4,199		2,964
Total Shareholders’ Equity		6,309		4,809
Total Liabilities and Shareholders’ Equity	$	12,384	$	10,831

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

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

	Year Ended December 31, 2008	2007	2006
Cash Flows from Operating Activities			
Net income	$ 1,350	$ 944	$ 678
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	791	736	633
Dry hole expense	84	90	70
Impairment of assets	294	4	9
Gain on sale of assets	(5)	(12)	(220)
Deferred income taxes	359	292	194
Income from equity method investees	(174)	(211)	(139)
Dividends from equity method investees	221	227	37
Unrealized (gain) loss on commodity derivative instruments	(522)	(2)	9
Settlement of previously recognized hedge losses	(194)	(183)	406
Allowance for doubtful accounts	49	14	19
Loss on involuntary conversion	9	51	-
Other	26	91	82
Changes in operating assets and liabilities, net of acquisition:			
Decrease (increase) in accounts receivable	121	(22)	(32)
(Increase) decrease in other current assets	(37)	8	(5)
Decrease in probable insurance claims	20	108	140
(Decrease) increase in accounts payable	(142)	19	(11)
Increase (decrease) in other current liabilities	35	(137)	(140)
Net Cash Provided by Operating Activities	2,285	2,017	1,730
Cash Flows From Investing Activities			
Additions to property, plant and equipment	(1,971)	(1,414)	(1,357)
Acquisitions, net of cash acquired	(292)	-	(412)
Proceeds from sale of property, plant and equipment	131	9	520
Distributions from equity method investees, net	-	2	151
Net Cash Used in Investing Activities	(2,132)	(1,403)	(1,098)
Cash Flows From Financing Activities			
Exercise of stock options	27	25	63
Excess tax benefits from stock-based awards	24	20	26
Cash dividends paid	(115)	(75)	(49)
Purchase of treasury stock	(3)	(102)	(399)
Proceeds from credit facilities	951	280	480
Repayment of credit facilities	(525)	(255)	(605)

Repurchase of senior debentures		(7)		-		-
Repayment of installment notes		(25)		-		-
Repayment of term loans		-		-		(105)
Net Cash Provided by (Used in) Financing Activities		327		(107)		(589)
Increase in Cash and Cash Equivalents		480		507		43
Cash and Cash Equivalents at Beginning of Period		660		153		110
Cash and Cash Equivalents at End of Period	$	1,140	$	660	$	153

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

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

	Year Ended December 31,		
	2008	2007	2006
Common Stock			
Balance, beginning of year	$ 636	$ 629	$ 616
Exercise of stock options	4	5	13
Restricted stock awards, net	1	2	-
Balance, end of year	641	636	629
Capital in Excess of Par Value			
Balance, beginning of year	2,106	2,041	1,945
Stock-based compensation expense	39	27	12
Exercise of stock options	23	20	50
Tax benefits related to exercise of stock options	24	20	26
Restricted stock awards, net	(1)	(2)	-
Rabbi trust shares sold	2	-	13
Adoption of SFAS 123(R), net of tax	-	-	(5)
Balance, end of year	2,193	2,106	2,041
Accumulated Other Comprehensive Loss			
Balance, beginning of year	(284)	(140)	(784)
Oil and gas cash flow hedges:			
Realized amounts reclassified into earnings	207	33	145
Unrealized amounts reclassified into earnings	-	-	265
Unrealized change in fair value	-	(184)	250
Net change in other	(33)	7	17
Adoption of SFAS 158, net of tax	-	-	(33)
Balance, end of year	(110)	(284)	(140)
Treasury Stock at Cost			
Balance, beginning of year	(613)	(511)	(148)
Purchases of treasury stock	(3)	(102)	(399)
Rabbi trust shares sold	2	-	36
Balance, end of year	(614)	(613)	(511)
Deferred Compensation - Restricted Stock			
Balance, beginning of year	-	-	(5)
Adoption of SFAS 123(R), net of tax	-	-	5
Balance, end of year	-	-	-
Retained Earnings			
Balance, beginning of year	2,964	2,095	1,466
Net income	1,350	944	678
Cash dividends ($0.660, $0.435, and $0.275 per share, respectively)	(115)	(75)	(49)
Balance, end of year	4,199	2,964	2,095
Total Shareholders' Equity	$ 6,309	$ 4,809	$ 4,114

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

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

	Year Ended December 31, 2008	2007	2006
Net income	$ 1,350	$ 944	$ 678
Other items of comprehensive income (loss)			
Oil and gas cash flow hedges:			
Realized amounts reclassified into earnings	331	54	232
Less tax provision	(124)	(21)	(87)
Unrealized change in fair value	-	(295)	352
Less tax provision	-	111	(102)
Unrealized amounts reclassified into earnings	-	-	424
Less tax provision	-	-	(159)
Net change in other	(52)	11	25
Less tax provision	19	(4)	(8)
Other comprehensive income (loss)	174	(144)	677
Comprehensive income	$ 1,524	$ 800	$ 1,355

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

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Noble Energy, Inc.

Notes to Consolidated Financial Statements

Note 1—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, the North Sea 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 reserve 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 reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the vice president in charge of corporate reserves and certain members of senior management. See Supplemental Oil and Gas Information.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment and goodwill, asset retirement obligations, valuation allowances for receivables and deferred income tax assets, valuation of derivative instruments, and obligations related to employee benefits, among others. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The current illiquid credit market combined with volatile commodity prices has 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 2007 and 2006 consolidated financial statements to conform to the 2008 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. 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 7 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—In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," 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 reserve 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.

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During fourth quarter, 2008, due to declines in commodity prices, we assessed the recoverability of our proved oil and gas properties and other long-lived assets and recorded impairment charges. See Note 3 – Asset Impairments. It is reasonably possible that other proved oil and gas properties or long-lived assets could become impaired in the future if commodity prices continue to decline.

We recorded impairments of $4 million in 2007 and $9 million in 2006, primarily related to downward reserve revisions on US properties and/or adjustment of the carrying value of properties to their fair values.

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 adjacent leaseholds, our geologists' evaluation of the lease, and the remaining months in the lease term.

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. It is reasonably possible that other individually significant unproved oil and gas properties could become impaired in the future if commodity prices continue to decline.

We recorded impairments of individually significant unproved properties of $3 million in 2007 and $1 million in 2006 and included the amounts in exploration expense.

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 reserve 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 autos, 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.

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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 $33 million in 2008, $17 million in 2007, and $13 million in 2006.

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.

Derivative Instruments and Hedging Activities—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of commodity price fluctuations. Such instruments include variable to fixed price commodity swaps, costless collars and variable to fixed price basis swaps. We account for derivative instruments and hedging activities in accordance with SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities, as amended” (SFAS 133). SFAS 133 established accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded on the balance sheet as either an asset or liability measured at fair value. SFAS 133 requires that changes in the derivative instrument’s fair value 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 and losses are then offset against related results on the hedged transaction in the statements of operations. Gains and losses from derivative instruments related to 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.

SFAS 133 also requires that a company 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 provide greater flexibility in our use of derivative instruments. 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 does not require adjustments to our previously reported financial statements.

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Goodwill—Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. We account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). Goodwill is not amortized to earnings but is tested annually during 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, 2008. However, it is reasonably possible that goodwill could become impaired in the future if commodity prices continue to decline. Changes in the carrying amount of goodwill are as follows:

	Year Ended December 31, 2008	2007
	(in millions)	
Balance, beginning of period	$ 761	$ 781
Tax adjustments related to acquisitions	-	(15)
Tax benefits on stock options exercised	(2)	(5)
Balance, end of period	$ 759	$ 761

We reduce the amount of goodwill originally recorded for deferred tax assets associated with the exercise of fully-vested stock options assumed in conjunction with the Patina Merger 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.

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.

Statement of Operations Information- Additional statement of operations information is as follows:

	Year Ended December 31, 2008	2007	2006
		(in millions)	
Other Revenues			
Electricity sales (1)	$ 56	$ 71	$ 72
Gathering, marketing and processing	20	24	28
Total	$ 76	$ 95	$ 100
Other Operating Expense, net			
Electricity generation(1)	$ 57	$ 57	$ 59
Gathering, marketing and processing	19	17	19
Loss on involuntary conversion of assets (2)	9	51	-
Other operating (income) expense, net (3)	44	20	33
Total	$ 129	$ 145	$ 111
Other Expense, net			

Deferred compensation (income) expense (4)	$	(32)	$	33	$	16
Interest income		(20)		(19)		(3)
Other (income) expense, net		7		(7)		1
Total	$	(45)	$	7	$	14

(1) 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 DD&A and increases in the allowance for doubtful accounts of $11 million in 2008, $14 million in 2007 and $15 million in 2006. See Allowance for Doubtful Accounts below.

(2) See Note 4 – Acquisitions and Divestitures – Main Pass Asset.

(3) Includes $38 million write-down of SemCrude, L.P. receivable in third quarter 2008. See Note 17 – Commitments and Contingencies.

(4) Amount represents increases (decreases) in the fair value of Noble Energy common stock held in a rabbi trust. See Note 12 – Benefit Plans.

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Balance Sheet Information – Additional balance sheet information is as follows:

	December 31, 2008		December 31, 2007	
	(in millions)			
Other Current Assets				
Inventories	$	105	$	60
Prepaid expenses and other		27		27
Total	$	132	$	87
Other Noncurrent Assets				
Equity method investments	$	311	$	357
Mutual fund investments		84		124
Commodity derivative instruments		33		5
Other assets		35		70
Total	$	463	$	556
Other Current Liabilities				
Accrued and other current liabilities	$	215	$	207
Short-term borrowings		25		25
Asset retirement obligations		27		13
Interest payable		9		18
Deferred gain on asset sale		24		-
Total	$	300	$	263
Other Noncurrent Liabilities				
Deferred compensation liabilities	$	159	$	225
Commodity derivative instruments		2		83
Asset retirement obligations		184		131
Accrued benefit costs		81		51
Other noncurrent liabilities		60		61
Total	$	486	$	551

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:

	Year Ended December 31, 2008		2007		2006	
			(in millions)			
Cash paid during the year for						
Interest, net of amount capitalized	$	76	$	105	$	106
Income taxes paid, net		263		149		115
Non-cash financing and investing activities						
Issuance of notes for property interests		-		50		-

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 are as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Balance, beginning of period	$ 50	$ 35	$ 19
Charged to expense	49	14	19
Deductions and other	(2)	1	(3)
Balance, end of period	$ 97	$ 50	$ 35

During third quarter 2008, we increased the allowance by $38 million for the probable loss on a receivable from SemCrude, L.P., a crude oil purchaser. See Note 17 - Commitments and Contingencies.

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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. However, we have not yet received any funds related to the settlement. We will reverse our allowance for doubtful accounts upon receipt of payment from the Ecuadorian government.

Amounts charged to expense include $11 million in 2008, $14 million in 2007 and $15 million in 2006 to cover potentially uncollectible balances related to the Ecuador power operations. The allowance was also increased by $2 million in 2006 to record various provisions related to our US business.

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 at December 31, 2008:

	December 31, 2008	December 31, 2007
	(in millions)	
Materials and supplies	$ 92	$ 56
Crude oil	13	4
Total inventories	$ 105	$ 60

Basic and Diluted Earnings Per Share—Basic earnings per share (EPS) of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding common stock equivalents. See Note 14 – Earnings Per Share.

Related Party Transactions—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, the Board member served as a consultant to the combined company for a period of 12 months following the merger (May 16, 2005) in exchange for a monthly retainer of $50,000. In 2007, we reimbursed his office space rent of $42,000. In 2006, we paid consulting fees of $225,806 and reimbursed his office space rent of $72,000.

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—During 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. During 2006, Trafigura Beheer B.V. was the largest single non-affiliated purchaser of production and accounted for 28% of crude oil sales, or 15% of total oil, gas and NGL sales. Shell Trading (US) Company accounted for 18% of 2006 crude oil sales or 10% of 2006 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 operation 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, 2008 is located in our foreign subsidiaries. The cash is denominated in US dollars and invested in highly liquid, investment-grade securities, US Treasury securities 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 primarily from sales of crude oil, natural gas and NGL production 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.

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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 from our largest international crude oil purchaser. However, we do not have all of our trade credit enhanced 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, L.P., a crude oil purchaser, and recognized a pre-tax charge of $38 million for a probable loss. See Note 17 – Commitments and Contingencies.

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. 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 – Receivables/Payables Related to Commodity Derivative Instruments.

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 (income) expense, net on the statements of operations.

Adoption of SFAS 123(R)—We adopted SFAS No. 123(R), "Share-Based Payment" (SFAS 123(R)) as of January 1, 2006. SFAS 123(R) revised SFAS No. 123, "Accounting for Stock-Based Compensation" and nullified APB 25 and its related implementation guidance. SFAS 123(R) requires companies to measure the grant-date fair value of stock options and other stock-based compensation issued to employees and expense the fair value over the requisite service period of the award. SFAS 123(R) became effective for interim or annual periods beginning January 1, 2006. See Note 13—Stock-Based Compensation.

Adoption of SFAS 157 – We adopted SFAS No. 157, "Fair Value Measurements" (SFAS 157), as of January 1, 2008 as related to our financial assets and liabilities. SFAS 157 establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. As a result of adoption, we began incorporating a credit risk assumption into the measurement of certain assets and liabilities. Adoption of SFAS 157 did not have a significant impact on our consolidated financial statements. See Note 5 – Fair Value Measurements.

As of January 1, 2009, we adopted SFAS 157 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. Adoption of SFAS 157 for our existing nonfinancial assets and liabilities did not have a significant impact on our consolidated financial statements.

Adoption of SFAS 158—We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS 158) as of December

31, 2006. SFAS 158 requires plan sponsors of defined benefit pension and other postretirement benefit plans to recognize the funded status of their postretirement benefit plans in the statement of financial position, measure the fair value of plan assets and benefit obligations as of the date of the fiscal year-end statement of financial position, and provide additional disclosures. The effect of adoption on our financial position at December 31, 2006 was included in our consolidated balance sheets. Adoption of SFAS 158 had no effect on our results of operations for the year ended December 31, 2006. See Note 12—Benefit Plans.

Adoption of FSP FIN 39-1 – We adopted FASB Staff Position FIN 39-1, "An Amendment of FASB Interpretation No. 39" (FSP FIN 39-1), as of January 1, 2008. FSP FIN 39-1 addresses certain modifications to FIN 39, "Offsetting of Amounts Related to Certain Contracts." FSP FIN 39-1 allows 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, 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, 2008 and 2007, we had no significant cash collateral obligations.

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Adoption of FIN 48 – We adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48) as of January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes". FIN 48 prescribes 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. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We also adopted FASB Staff Position No. FIN 48-1, "Definition of Settlement in FASB Interpretation No. 48" (FSP FIN 48-1) as of January 1, 2007. FSP FIN 48-1 provides 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. The adoption of FIN 48 and FSP FIN 48-1 had no effect on our financial position or results of operations. See Note 9—Income Taxes.

Note 3 – 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 oil and gas properties and other investments as of December 31, 2008. As a result of this analysis we determined that certain of our assets were impaired. In addition, during third quarter 2008, we recorded an impairment charge related to an asset held for sale. Total pre-tax (non-cash) impairments for 2008 were $294 million.

Total asset impairment charges assessed under FAS 144 for 2008 were $219 million, of which $149 million related to our US proved properties and $70 million related to our investment in Ecuador. These 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 December 31, 2008 commodity price strips, operating and development costs, as well as appropriate discount rates.

We also perform periodic assessments related to our individually significant unproved properties. We recorded an impairment charge of $75 million related to our US unproved properties. These impairments 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, as well as appropriate discount rates.

Note 4—Acquisitions and Divestitures

Mid-continent Acquisition – In July 2008, we acquired producing properties in western Oklahoma for $292 million in cash. The total purchase price has been preliminarily 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.

Main Pass Asset – We have initiated a process to sell our remaining operated non-core Gulf of Mexico shelf asset. This asset, located at Main Pass, suffered significant hurricane damage in 2004 and 2005 and has undergone cleanup activities that were completed in the third quarter of 2007. During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for damage and 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 2008, in anticipation of the sale, we recorded an impairment loss of $38 million (based on anticipated proceeds less costs to sell) related to the Main Pass asset. We also recorded a loss on involuntary conversion of $9 million upon resolution of our insurance claims related to the hurricane damage sustained in 2005. An asset held for sale of $26 million is included in current assets and associated asset retirement obligations of $15 million are included in current liabilities in our consolidated balance sheets at December 31, 2008.

Through December 31, 2008, we received $330 million of insurance recoveries related to damage caused by Hurricanes Ivan and Katrina. As of December 31, 2008, we recorded probable insurance claims of $10 million. Insurance reimbursements received for cleanup and repair costs are included in cash flows from operating activities.

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 is subject to Argentine government approval, which has not been received.

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Accordingly, the gain on sale of approximately $24 million has been deferred in other current liabilities until approval is obtained. We are currently unable to predict when government approval will be obtained.

Sale of Gulf of Mexico Shelf Properties—In 2006, we completed the sale of essentially all of our Gulf of Mexico shelf properties except for the Main Pass asset which required repairs related to hurricane damage at the time. Pretax cash proceeds from the sale totaled $506 million including proceeds received from parties who exercised preferential rights to purchase certain minor properties. We recorded a pretax gain of $211 million from the sale. The net book value of properties sold totaled $229 million. Asset retirement obligations of $45 million, related to the Gulf of Mexico shelf properties, were also included in the sale. In accordance with SFAS 142, we allocated $100 million of our US reporting unit goodwill to the sale. The property disposition did not qualify for accounting as discontinued operations, in accordance with EITF 03-13, “Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations”. This is due to the migration of our investment and operations to the deepwater Gulf of Mexico which we believe is an area of higher potential.

As a result of the sale, we recognized a pretax charge of $399 million related to cash flow hedge losses which were reclassified from AOCL to earnings. This reclassification reflected the mark-to-market value of the cash flow hedges that related to Gulf of Mexico shelf production. See Note 6—Derivative Instruments and Hedging Activities.

Purchase of U.S. Exploration Holdings, Inc.—In 2006, we purchased the common stock of U.S. Exploration, a privately held corporation, for a cash purchase price of $412 million plus liabilities assumed. U.S. Exploration’s reserves and production are located in Colorado’s Wattenberg field. The total purchase price was allocated to the assets acquired and liabilities assumed based on fair values at the acquisition date as follows:

- $413 million to proved oil and gas properties;
- $131 million to unproved oil and gas properties;
- $34 million to goodwill; and
- $172 million to deferred income taxes.

Note 5 – Fair Values of Financial Instruments

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

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.

Commodity Derivative Instruments – Our commodity derivative instruments consist of variable to fixed price commodity swaps, costless collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves for the underlying commodities 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 also include a measure of counterparty credit risk or our own nonperformance risk based on the current published credit default swap rates. In addition, for costless 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. See Note 6 – Derivative Instruments and Hedging Activities.

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Fair value information for financial assets and liabilities that are measured at fair value each reporting period is as follows at December 31, 2008:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustment (1)	Fair Value Measurement
			(in millions)		
Financial assets					
Mutual fund investments	$ 84	$ -	$ -	$ -	$ 84
Commodity derivative instruments	-	492	-	(22)	470
Financial liabilities					
Commodity derivative instruments	-	(47)	-	22	(25)

(1) Amount represents the impact of master netting agreements that allow us to settle asset and liability positions with the same counterparty.

SFAS 157, which we adopted as of January 1, 2008, 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.

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.

Additional information regarding our debt is as follows:

	December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Total debt, net of unamortized discount	$ 2,266	$ 2,172	$ 1,876	$ 1,920

Note 6—Derivative Instruments and Hedging Activities

Commodity Derivative Instruments—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of commodity price fluctuations on cash flows. Such instruments include variable to fixed price commodity swaps, costless 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 SFAS 133 and all derivative instruments are reflected at fair value on 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, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments effective January 1, 2008. See Note 5 – Fair Values of Financial Instruments for a discussion of methods and assumptions used to estimate the fair values of our commodity derivative instruments.

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The components of (gain) loss on commodity derivative instruments included in the consolidated statements of operations include the following:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Unrealized gain on commodity derivative instruments	$ (522)	$ -	$ -
Realized (gain) loss on commodity derivative instruments	82	-	(41)
Reclassified from AOCL (1)	-	-	424
Ineffectiveness (gain) loss	-	(2)	9
(Gain) loss on commodity derivative instruments	$ (440)	$ (2)	$ 392

(1) Under our previous cash flow hedge accounting, if it became probable that the hedging instrument was no longer highly effective, the hedging instrument lost hedge accounting treatment. All current mark-to-market gains and losses were recorded in earnings and all accumulated gains or losses recorded in AOCL related to the hedging instrument were also reclassified to earnings. During 2006, we reclassified a pretax charge of $399 million from AOCL to earnings when it became probable that forecasted crude oil and natural gas sales would not occur due to the sale of Gulf of Mexico shelf properties. A mark-to-market gain of $39 million and the reclassification of a pretax charge of $25 million from AOCL to earnings due to the impacts of Hurricanes Katrina and Rita on the timing of forecasted Gulf of Mexico production were also included in 2006.

Crude oil and natural gas sales include amounts reclassified from AOCL as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
(Decrease) in crude oil sales	$ (365)	$ (223)	$ (191)
Increase (decrease) in natural gas sales	34	169	(41)
Total (decrease) in crude oil and natural gas sales	$ (331)	$ (54)	$ (232)

As of December 31, 2008 and 2007, the balance in AOCL included net deferred losses of $48 million and $255 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 $29 million and $153 million, respectively. Approximately $36 million of 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, 2008 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 $57 million before tax. All forecasted transactions currently being hedged are expected to occur by December 2010.

As of December 31, 2008, we had entered into the following crude oil derivative instruments:

	Variable to Fixed Price Swaps			Costless Collars			
Production Period	Index	Bbls Per Day	Weighted Average Fixed Price	Index	Bbls Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2009	NYMEX WTI	9,000	$ 88.43	NYMEX WTI	6,700	$ 79.70	$ 90.60
2009		2,000	87.98		5,074	70.62	87.93

2009 Average	Dated Brent	11,000	88.35	Dated Brent	11,774	75.79	89.45
2010				NYMEX WTI	5,500	69.00	85.65

From January 1, 2009 to February 18, 2009, we entered into additional NYMEX WTI costless collars covering 2,000 Bbls per day for calendar year 2010.

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As of December 31, 2008, we had entered into the following natural gas derivative instruments:

		Costless Collars		
Production Period	Index	MMBtu Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
2009	NYMEX HH	170,000	$ 9.15	$ 10.81
2009	IFERC CIG (1)	15,000	6.00	9.90
2009 Average		185,000	8.90	10.73
2010	IFERC CIG	15,000	6.25	8.10

(1) Colorado Interstate Gas – Northern System

As of December 31, 2008, we had entered into the following natural gas basis swaps:

		Basis Swaps		
Production Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2009	IFERC CIG	NYMEX HH	140,000	$ 2.49
2010	IFERC CIG	NYMEX HH	20,000	1.99

From January 1, 2009 to February 18, 2009, we entered into additional IFERC CIG basis swaps covering 30,000 MMBtu per day for calendar year 2010.

The costless 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.

Other Derivative Instruments—In addition to the derivative instruments described above, we may employ derivative instruments in connection with purchases and sales of production in order to establish a fixed margin and mitigate the risk of price volatility. Most of the purchases are on an index basis. However, purchasers in the markets in which we sell often require fixed or NYMEX-related pricing. We may use a derivative instrument to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

Receivables/Payables Related to Commodity Derivative Instruments—The fair values of derivative instruments included in the consolidated balance sheets are as follows:

	December 31, 2008	December 31, 2007
	(in millions)	
Commodity derivative instruments		
Current asset	$ 437	$ 15
Long-term asset	33	5
Current liability	(23)	(540)
Long-term liability	(2)	(83)

Interest Rate Lock—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, 2008 and 2007, AOCL included deferred losses, net of tax, of $3 million and $4 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.

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As of December 31, 2007, we had 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.

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, 2008	2007	2006
		(in millions)	
Capitalized exploratory well costs, beginning of period	$ 249	$ 80	$ 35
Additions to capitalized exploratory well costs pending determination of proved reserves	253	182	63
Reclassified to proved oil and gas properties based on determination of proved reserves	-	(7)	(17)
Capitalized exploratory well costs charged to expense	(1)	(6)	(1)
Capitalized exploratory well costs, end of period	$ 501	$ 249	$ 80

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, 2008	2007	2006
		(in millions)	
Exploratory well costs capitalized for a period of one year or less	$ 256	$ 187	$ 58
Exploratory well costs capitalized for a period greater than one year after completion of drilling	245	62	22
Balance, end of period	$ 501	$ 249	$ 80
Number of projects with exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	6	5	4

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, 2008:

	Total	Suspended Since 2007	2006	2005
		(in millions)		
Project				
West Africa	$ 160	$ 140	$ 1	$ 19
Raton South (deepwater Gulf of Mexico)	28	5	23	-

Redrock (deepwater Gulf of Mexico)		17		-		17		-
Flyndre (North Sea)		15		12		3		-
Selkirk (North Sea)		22		22		-		-
Other		3		-		3		-
Total exploratory well costs capitalized for a period greater than one year after completion of drilling	$	245	$	179	$	47	$	19

Exploratory well costs capitalized for more than one year at December 31, 2008 include six projects, one of which includes activity in West Africa. We incurred exploratory well costs of $160 million in West Africa for Blocks O and I offshore Equatorial Guinea and the PH-77 license 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. Accordingly, a development plan for the Benita discovery on Block I was submitted to the Equatorial Guinean government in December 2008, and we await their approval. In addition to the amount of exploratory well costs that have been capitalized for a period greater than one year for the West Africa project, we have incurred $108 million in suspended costs related to additional drilling activity in West Africa through December 31, 2008.

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Additionally, we incurred exploratory well costs related to two projects in the deepwater Gulf of Mexico. One project relates to Raton South (Mississippi Canyon Block 292) and includes $28 million of suspended exploratory well costs. A successful sidetrack well was recently completed on this prospect and tie-back to a host facility is anticipated in late 2009. The other project relates to Redrock (Mississippi Canyon Block 204) and includes $17 million of suspended exploratory well costs. Tie-back of Redrock is anticipated to occur following the tie-back of Raton South.

The Flyndre and Selkirk projects are located in the UK sector of the North Sea and incurred exploratory well costs of $15 million and $22 million, respectively. We successfully completed an exploratory appraisal well at each project in 2007 and are working with the co-venturers to formulate development plans.

The remaining project, which totals $3 million in suspended exploratory well costs, continues to be evaluated by various means including additional seismic work, drilling additional wells and evaluating the potential of the exploration well.

Note 8—Debt

Our debt consists of the following:

	December 31,			
	2008		2007	
	Debt	Interest Rate	Debt	Interest Rate
	(in millions, except percentages)			
Credit facility	$ 1,606	0.80%	$ 1,180	5.28%
5 ¼% Senior Notes, due April 15, 2014	200	5.25%	200	5.25%
7 ¼% Notes, due October 15, 2023	100	7.25%	100	7.25%
8% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
7 ¼% Senior Debentures, due August 1, 2097	89	7.25%	100	7.25%
Installment payments, due May 11, 2009	-	-	25	5.53%
Long-term debt	2,245		1,855	
Installment payments - current portion	25	4.18%	25	5.53%
Total debt	2,270		1,880	
Unamortized discount	(4)		(4)	
Total debt, net of discount	$ 2,266		$ 1,876	

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 the 7¼% Notes, the 8% Senior Notes and the 7¼% Senior Debentures 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 $6 million (including $2 million related to the credit facility) remain and are being amortized to expense over the life of the related debt issue.

Credit Facility—In November 2007, we extended our bank revolving credit facility (the credit facility) until 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. 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, 2008, we were in full compliance with our debt covenants. The credit facility is with certain commercial lending institutions and is available for general corporate purposes.

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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.

Installment Payment Due 2009—During 2007, we purchased working interests in oil and gas properties in the Piceance basin of western Colorado for $75 million. After making cash payments of $25 million at closing and $25 million during 2008, we owe $25 million to the seller. The final $25 million installment is due on May 11, 2009. The amount due is included in short-term borrowings in our consolidated balance sheets. Interest on the unpaid amount is due quarterly and accrues at a LIBOR rate plus .30%. The interest rate was 4.18% at December 31, 2008.

Debt Repurchase— During 2008, we repurchased $11 million of our 7¼% Senior Debentures due August 1, 2097, recognizing a debt extinguishment gain of $4 million.

Annual Maturities—Annual maturities of outstanding debt are as follows:

	(in millions)
2009	$ 25
2010	-
2011	-
2012	1,606
2013	-
Thereafter	639
Total	$ 2,270

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, 2008 or 2007.

Note 9—Income Taxes

Components of income before income taxes are as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Domestic	$ 1,032	$ 480	$ 402
Foreign	1,029	888	694
Total	$ 2,061	$ 1,368	$ 1,096

The income tax provision consists of the following:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	

Current taxes			
Federal	$ 45	$ 6	$ 80
State	1	1	6
Foreign	306	125	138
Total current	352	132	224
Deferred taxes			
Federal	363	186	144
State	4	6	5
Foreign	(8)	100	45
Total deferred	359	292	194
Total income tax provision	$ 711	$ 424	$ 418

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

	Year Ended December 31,		
	2008	2007	2006
	(amounts in percentages)		
Federal statutory rate	35.0	35.0	35.0
Effect of			
Earnings of equity method investees	(2.9)	(5.4)	(4.2)
State taxes, net of federal benefit	0.2	0.5	1.3
Difference between US and foreign rates	1.8	1.6	2.2
Nondeductible goodwill	-	-	3.1
Other, net	0.4	(0.7)	0.7
Effective rate	34.5	31.0	38.1

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2008	2007
	(in millions)	
Deferred tax assets		
Loss carryforwards	$ 36	$ 21
Ecuador investment	18	-
Accrued expenses	32	26
Allowance for doubtful accounts	20	4
Fair value of derivative instruments	-	177
AOCL - pension asset/obligation	20	-
Postretirement benefits	31	10
Deferred compensation	63	61
Foreign tax credits	51	82
Other	27	14
Total deferred tax assets	298	395
Valuation allowance - foreign loss carryforwards	(35)	(18)
Valuation allowance - foreign tax credits	(51)	(57)
Valuation allowance - Ecuador investment	(18)	-
Net deferred tax assets	194	320
Deferred tax liabilities		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(2,388)	(2,184)
Commodity derivative assets	(122)	-
Other	-	11
Total deferred tax liability	(2,510)	(2,173)
Net deferred tax liability	$ (2,316)	$ (1,853)

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

	December 31,	
	2008	2007
	(in millions)	
Deferred income tax asset	$ -	$ 131

Deferred income tax liability - current		(142)		-
Deferred income tax liability - noncurrent		(2,174)		(1,984)
Net deferred tax liability	$	(2,316)	$	(1,853)

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, 2008. 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.

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We have recognized deferred tax assets associated with foreign loss carryforwards. The tax effect of these carryforwards decreased from $90 million in 2006 to $18 million in 2007 and increased to $35 million in 2008. These losses continue to be incurred on our projects in Suriname and other new venture activities which are not yet commercial. Therefore, a valuation allowance was provided against the full amount of the deferred tax assets. In 2006, we incurred a large taxable loss in the UK from accelerated write-offs allowed on our Dumbarton field development. No valuation allowance was provided against this loss carryforward, and it was fully utilized in 2007.

Starting in 2005, we were able to claim a foreign tax credit for US federal income tax purposes. As of December 31, 2007, we had recorded a deferred tax asset of $11 million for certain foreign taxes related primarily to 2005. Because it was uncertain whether a credit could be claimed for those taxes under limitations imposed by the Internal Revenue Code, a valuation allowance of $11 million was provided against the deferred tax asset. However, this uncertainty was favorably resolved when we amended our 2005 and 2006 federal income tax returns in 2008. Therefore, both the deferred tax asset and the valuation allowance have been eliminated as of December 31, 2008. We have also recorded a deferred tax asset of $51 million for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations. A valuation allowance of $51 million has been provided against this deferred tax asset. Finally, a deferred tax asset of $18 million was recorded in 2008 for the future tax benefit of an impairment of a foreign asset. However, this was fully offset by a valuation allowance.

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 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.

Several factors resulted in a decrease in our effective tax rate for 2007. The major factor was that, in 2006, $100 million of goodwill write-off associated with the sale of Gulf of Mexico shelf properties was not deductible, which increased the rate for that year. Other factors were an increase in deferred tax assets arising from foreign tax credits, a decrease in the Chinese tax rate, and the realization of additional income from equity method investees which is a favorable permanent difference in calculating the income tax expense.

We are currently reviewing the possibility of repatriating a portion of our international undistributed earnings. Therefore, as of December 31, 2008, we have recorded additional US deferred income taxes of $9 million on the portion of undistributed earnings of our foreign subsidiaries that are likely to be repatriated. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows. As of December 31, 2008, the accumulated undistributed earnings of the foreign subsidiaries on which no US taxes have been recorded were approximately $1.1 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 estimate 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.

During 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. The deferred tax liability for China as of December 31, 2006 was revised during 2007 to reflect the new rate, which decreased deferred tax expense by $2 million.

Adoption of FIN 48 and FSP FIN 48-1—As discussed in Note 2—Significant Accounting Policies, we adopted FIN 48 and FSP FIN 48-1 as of January 1, 2007. The adoption had no effect on our financial position or results of operations. We do 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. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. We did not accrue interest or penalties at December 31, 2008, 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.

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In our major tax jurisdictions, the earliest years remaining open to examination are as follows:

Tax Jurisdiction	Earliest Year Remaining Open to Examination
United States	2005
Equatorial Guinea	2006
China	2006
Israel	2000
UK	2006
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, 2008	2007
	(in millions)	
Asset retirement obligations, beginning of year	$ 144	$ 196
Liabilities incurred in current period	15	9
Liabilities settled in current period	(33)	(177)
Revisions	75	108
Accretion expense	10	8
Asset retirement obligations, end of year	$ 211	$ 144
Current portion	$ 27	$ 13
Noncurrent portion	184	131

For the year ended December 31, 2008, liabilities settled relate 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).

For the year ended December 31, 2007, approximately $125 million of liabilities settled and $64 million of revisions related to hurricane damage to the Gulf of Mexico Main Pass assets. The remainder of the liabilities settled and revisions resulted primarily from changes in estimated timing of actual abandonment and overall cost increases for Gulf of Mexico assets.

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, 2008, our retained earnings included $114 million related to the undistributed earnings of equity method investees.

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The carrying value of our AMPCO investment is $25 million higher than the underlying net assets of the investee. $13 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, 2008	December 31, 2007
	(in millions)	
Equity method investments		
AMPCO	$ 190	$ 200
Alba Plant	106	142
Other	15	15
Total equity method investments	$ 311	357

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

	December 31, 2008	December 31, 2007
	(in millions)	
Balance sheet information		
Current assets	$ 283	$ 408
Noncurrent assets	783	814
Current liabilities	248	273
Noncurrent liabilities	43	31

	Year Ended December 31, 2008	2007	2006
		(in millions)	
Statements of operations information			
Operating revenues	$ 1,022	$ 934	$ 702
Less cost of goods sold	250	220	202
Gross margin	772	714	500
Less other expense	37	36	48
Less income tax expense (1)	183	44	23
Net income	$ 552	$ 634	$ 429

(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.

Former Patina employees began participation in the pension plan and the restoration plan on January 1, 2006, with vesting service from their original Patina hire date and credited service for benefit accruals starting January 1, 2006. Additionally, all former Patina employees were covered under the medical and life insurance plans effective January 1, 2006.

On December 31, 2006, we adopted SFAS 158, which required us to 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 sheet, with a corresponding adjustment to AOCL, net of tax.

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The adjustment to AOCL at adoption represented the unrecognized net actuarial loss, unrecognized prior service cost, and unrecognized net transition obligation remaining from the initial adoption of SFAS No. 87, “Employers’ Accounting for Pensions” and SFAS No. 106, “Employers’ Accounting for Post-Retirement Benefits Other Than Pensions”. These amounts are currently being recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in periods subsequent to adoption and are not recognized as net periodic benefit cost in the same periods are recognized as a component of AOCL. The adoption of SFAS 158 had no effect on our consolidated statements of operations for the year ended December 31, 2006, for any prior period presented, or for any periods subsequent to adoption.

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	
	2008	2007	2008	2007
	(in millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$ 188	$ 175	$ 22	$ 22
Service cost	12	12	2	2
Interest cost	12	10	1	1
Amendments	-	8	-	-
Benefits paid	(17)	(6)	(1)	(1)
Actuarial (gain) loss	(1)	(11)	(2)	(2)
Benefit obligation at end of year	194	188	22	22
Change in plan assets				
Fair value of plan assets at beginning of year	155	137	-	-
Actual return on plan assets	(43)	13	-	-
Employer contributions	37	11	1	1
Benefits paid	(17)	(6)	(1)	(1)
Fair value of plan assets at end of year	132	155	-	-
Funded status				
Funded status at end of year	(62)	(33)	(22)	(22)
Net amount recognized in consolidated balance sheets (after adoption of FAS 158)	(62)	(33)	(22)	(22)
Amounts recognized in consolidated balance sheets consist of:				
Current liabilities	(2)	(3)	(1)	(1)
Noncurrent liabilities	(60)	(30)	(21)	(21)
Net amount recognized in consolidated balance sheets (after adoption of FAS 158)	(62)	(33)	(22)	(22)
Amounts not yet reflected in net periodic benefit cost and included in AOCL				
Transition obligation	-	(1)	-	-
Prior service (cost) credit	(3)	(3)	5	6
Accumulated loss	(86)	(34)	(10)	(14)
AOCL	(89)	(38)	(5)	(8)
Cumulative employer contributions in excess of net periodic benefit cost	27	5	(17)	(14)
	$ (62)	(33)	$ (22)	(22)

Net amount recognized in consolidated balance sheet
(after adoption of FAS 158)

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Net periodic benefit cost recognized for the pension, restoration and other postretirement benefit plans is provided in the table below:

	Retirement and Restoration Plans Year Ended December 31,			Medical and Life Plans Year Ended December 31,		
	2008	2007	2006	2008	2007	2006
	(in millions)					
Components of net periodic benefit cost						
Service cost	$ 12	$ 12	$ 12	$ 2	$ 2	$ 2
Interest cost	12	10	9	1	1	1
Expected return on plan assets	(12)	(11)	(9)	-	-	-
Amortization of prior service (credit) cost	-	-	-	(1)	(1)	-
Amortization of net loss	2	3	3	1	1	1
Net periodic benefit cost	$ 14	$ 14	$ 15	$ 3	$ 3	$ 4
Other changes recognized in AOCL						
Prior service cost arising during period	$ -	$ 8	*	$ -	$ -	*
Net loss (gain) arising during period	53	(13)	*	(3)	(3)	*
Amortization of prior service credit	-	-	*	1	1	*
Amortization of net loss	(2)	(3)	*	(1)	(1)	*
Total recognized in AOCL	$ 51	$ (8)	*	$ (3)	$ (3)	*
Expected amortizations for next fiscal year						
Amortization of prior service cost (credit)	$ -	$ -	$ (1)	$ (1)	$ (1)	$ (1)
Amortization of net loss	2	2	3	1	1	1
Weighted-average assumptions used to determine benefit obligations						
Discount rate (1)	6.00% / 6.25%	6.50%	5.75%	6.25%	6.25%	5.75%
Rate of compensation increase	5.00%	5.00%	5.00%	-	-	-
Weighted-average assumptions used to determine net periodic benefit costs						
Discount rate (2)	6.50%	5.75%	5.50% / 6.25%	6.25%	5.75%	5.50% / 6.25%
Expected long-term rate of return on plan assets	8.25%	8.25%	8.25%	-	-	-
Rate of compensation increase	5.00%	5.00%	5.00%	-	-	-

* Not applicable due to change in method of accounting for defined benefit and other post retirement plans.
(1) The discount rate was 6.00% for the retirement plan and 6.25% for the restoration plan at December 31, 2008.
(2) The net periodic benefit cost was remeasured at May 1, 2006 using a discount rate of 6.25%, due to changes in plan provisions.

Additional disclosures are as follows:

	Retirement and Restoration Plans	
	2008	2007
	(in millions)	
Accumulated benefit obligation	$ 169	$ 163
Information for pension plans with projected benefit obligations in excess of plan assets		
Projected benefit obligation	194	188
Fair value of plan assets	132	155
Information for pension plans with accumulated benefit obligations in excess of plan assets		
Accumulated benefit obligation	169	25
Fair value of plan assets	132	-

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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 8.25% per annum over the life of the plan for the calculation of 2008 net periodic benefit cost. The assumption will be reduced to 8.00% for the calculation of 2009 net periodic benefit cost. No plan assets are expected to be returned to us during 2009.

In order to determine an appropriate discount rate at December 31, 2008, 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 2008. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of approximately $2 million in 2008.

Assumed health care cost trend rates were as follows at December 31:

	2008	2007
Health care cost trend rate assumed for next year	8%	9%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5%	5%
Year rate reaches ultimate trend rate	2012	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
	(in millions)	
Effect on total service and interest cost components for 2008	$ -	$ -
Effect on year-end 2008 postretirement benefit obligation	2	(2)

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

	Target Allocation	Plan Assets	
	2009	2008	2007
Asset Category			
Equity securities	70%	65%	70%
Fixed income	30%	35%	30%
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. 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 2008.

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, 2008, we had cumulative asset gains of approximately $3 million, which remain to be recognized in the calculation of the market-related value of assets.

Contributions—As a result of previous contributions made to the pension plan, there are no required contributions expected during 2009. During January 2009, we made a voluntary contribution of $1 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 during 2009.

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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, 2008, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plans	Medical and Life Plans
	(in millions)	
2009	$ 18	$ 1
2010	13	2
2011	16	2
2012	17	2
2013	16	2
Years 2014 to 2018	99	14

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2008 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 $7 million in 2008, $6 million in 2007, and $4 million in 2006.

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. We account for the deferred compensation plan in accordance with EITF 97-14, “Accounting for Deferred Compensation Arrangements Where Amounts Earned are Held in a Rabbi Trust and Invested” (EITF 97-14). Components of the rabbi trust are as follows:

	December 31,	
	2008	2007
	(in millions, except share amounts)	
Rabbi trust assets		
Mutual fund investments	$ 71	$ 107
Noble Energy common stock (at market value) (1)	52	87
Total rabbi trust assets	123	194
Liability under Patina deferred compensation plan	$ 123	$ 194
Number of shares of Noble Energy common stock held by rabbi trust	1,051,032	1,101,032

(1) Shares of Noble Energy 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 market value. We account for these investments in accordance with SFAS No. 115, “Accounting for Certain Investments in Debt and Equity Securities.” The mutual funds are included in the mutual funds 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, 2008 were attributable to a member of our Board of Directors. Plan participants sold 50,000 shares of common stock during 2008, no shares during 2007, and 1,067,948 shares during 2006. Proceeds were invested in mutual funds. Distributions to plan participants totaled $1 million in 2008, $2 million in 2007, and $0.5 million in 2006.

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In accordance with EITF 97-14, all fluctuations in market value of the deferred compensation liability have been reflected in other expense, net in the consolidated statements of operations. We recognized deferred compensation income of $32 million in 2008 and deferred compensation expense of $33 million in 2007 and $16 million in 2006.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. A deferred compensation liability of $36 million was outstanding at December 31, 2008 under the unfunded plan.

Note 13 – Stock-Based Compensation

As discussed in Note 2—Summary of Significant Accounting Policies, effective January 1, 2006, we adopted the fair value recognition provisions for stock-based awards granted to employees. SFAS 123(R) requires companies to recognize in the statement of operations the grant-date fair value of stock options and other stock-based compensation issued to employees. We recognize the expense of all stock-based awards on a straight-line basis over the employee's requisite service period (generally the vesting period of the award).

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Stock-based compensation expense included in			
General and administrative expense	$ 38	$ 25	$ 11
Exploration expense and other	1	2	1
Total stock-based compensation expense	$ 39	$ 27	$ 12
Tax benefit recognized	$ (15)	$ (10)	$ (4)

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. During 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 18,500,000 to 22,000,000 shares. At December 31, 2008, 10,469,623 shares of common stock were reserved for issuance, including 4,698,788 shares available for future grants and awards, under the 1992 Plan.

1992 Plan Stock Options—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.

1992 Plan Restricted Stock—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.

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 the provisions of SFAS 123(R) 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 are accounted for under SFAS No. 5, "Accounting for Contingencies" and are excluded from the provisions of SFAS 123(R).

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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 common stock that may be issued under the 2005 Plan is 800,000. At December 31, 2008, 739,204 shares of common stock were reserved for issuance, including 620,675 shares available for future grants and awards under the 2005 Plan.

2005 Plan Stock Options—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.

2005 Plan Restricted Stock—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 market 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 Patina options expire five years from the date of grant.

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.

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The assumptions used in valuing stock options were as follows:

	Year Ended December 31, 2008	2007	2006
		(weighted averages)	
Expected term (in years)	5.5	5.5	5.5
Expected volatility	27.7%	29.6%	31.8%
Risk-free rate	2.9%	4.7%	4.7%
Expected dividend yield	1.0%	0.6%	0.8%

Stock option activity was as follows:

	Options	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2007	6,175,061	$ 32.98		
Granted	1,139,758	73.14		
Exercised	(1,080,116)	24.31		
Forfeited	(152,328)	61.22		
Outstanding at December 31, 2008	6,082,375	$ 41.41	5.6	$ 80
Exercisable at December 31, 2008	3,927,682	$ 29.80	3.9	$ 79

The weighted-average grant-date fair value of options granted was $20.40 in 2008, $18.77 in 2007, and $16.09 in 2006. The total intrinsic value of options exercised was $67 million in 2008, $68 million in 2007, and $118 million in 2006.

As of December 31, 2008, $24 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.3 years. We issue new shares of 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 (per share)	Shares Subject to Market Conditions	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2007	567,590	$ 52.33	124,137	$ 33.11
Granted	462,917	73.92	-	-
Vested	(80,347)	52.46	(54,199)	29.87
Forfeited	(59,133)	61.78	(1,445)	45.94
Outstanding at December 31, 2008	891,027	$ 62.91	68,493	$ 35.40

The total fair value of restricted stock that vested was $10 million in 2008, $6 million in 2007, and $2 million in 2006.

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 the assumptions in the following table. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility represents the extent to which our stock price is expected to fluctuate between 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.

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The assumptions used in valuing the market-based restricted stock awards were as follows:

	Year Ended December 31, 2006
Number of simulations	100,000
Expected volatility	28.4%
Risk-free rate	4.4%

As of December 31, 2008, $30 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 1.8 years. Common stock dividends accrue on restricted stock grants and are paid upon vesting. We issue new shares of common stock when awarding restricted stock.

Note 14 – Earnings Per Share

Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock may include the effect of Noble Energy 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,					
	2008		2007		2006	
	Income	Shares	Income	Shares	Income	Shares
	(in millions, except share and per share amounts)					
Net income	$ 1,350	173	$ 944	171	$ 678	176
Basic Earnings per Share	$ 7.83		$ 5.52		$ 3.86	
Net income	$ 1,350	173	$ 944	171	$ 678	176
Effect of dilutive stock options and restricted stock awards	-	2	-	2	-	3
Effect of shares of Noble Energy common stock held in rabbi trust	(20)	1	-	-	-	-
Net income available to common shareholders	$ 1,330	176	$ 944	173	$ 678	179
Diluted Earnings per Share (1)	$ 7.58		$ 5.45		$ 3.79	

(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 Noble Energy shares held in a rabbi trust. When dilutive, the deferred compensation gain or loss (net of tax) is excluded from net income while the Noble Energy shares held in the rabbi trust are included in the diluted share count.

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Options, restricted stock and shares of our common stock held in a rabbi trust excluded from the EPS calculation above as they were antidilutive are as follows:

	Weighted Outstanding Awards and Shares	Weighted Average Exercise Price
	(in millions, except per share amounts)	
Year Ended December 31, 2008		
Stock options	1	$ 67.64
Total excluded from diluted EPS calculation	1	
Year Ended December 31, 2007		
Stock options	1	$ 52.41
Noble Energy common stock held in rabbi trust and shares of restricted stock	1	
Total excluded from diluted EPS calculation	2	
Year Ended December 31, 2006		
Stock options	1	$ 45.19
Noble Energy common stock held in rabbi trust and shares of restricted stock	1	
Total excluded from diluted EPS calculation	2	

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 and production: the United States; West Africa; the North Sea; Israel; and Other International, Corporate and Marketing. Other International includes Argentina (through February 2008), China, Ecuador and Suriname.

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.

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	Total	United States	West Africa	North Sea	Israel	Other Int'l, Corporate & Marketing
			(in millions)			
Year Ended December 31, 2008						
Revenues from third parties	$ 4,058	$ 2,315	$ 541	$ 410	$ 157	$ 635
Amount reclassified from AOCL (1)	(331)	(290)	(41)	-	-	-
Intersegment revenue	-	434	-	-	-	(434)
Income from equity method investees	174	-	174	-	-	-
Total Revenues	3,901	2,459	674	410	157	201
DD&A	791	646	34	55	24	32
Loss on involuntary conversion of assets	9	9	-	-	-	-
Impairment of assets	294	224	-	-	-	70
Gain on derivative instruments	(440)	(363)	(77)	-	-	-
Income (loss) before income taxes	2,061	1,333	689	284	122	(367)
Equity method investments	311	-	311	-	-	-
Additions to long-lived assets	2,179	1,842	143	94	39	61
Total assets at December 31, 2008 (2)	12,384	9,212	1,614	775	366	417
Year Ended December 31, 2007						
Revenues from third parties	$ 3,115	$ 1,651	$ 418	$ 364	$ 113	$ 569
Amount reclassified from AOCL (1)	(54)	(42)	(12)	-	-	-
Intersegment revenue	-	343	-	-	-	(343)
Income from equity method investees	211	-	211	-	-	-
Total Revenues	3,272	1,952	617	364	113	226
DD&A	736	580	25	81	18	32
Loss on involuntary conversion of assets	51	51	-	-	-	-
Impairment of assets	4	4	-	-	-	-
Gain on derivative instruments	(2)	(2)	-	-	-	-
Income (loss) before income taxes	1,368	810	517	221	86	(266)
Equity method investments	357	-	357	-	-	-
Additions to long-lived assets	1,623	1,285	151	83	26	78
Total assets at December 31, 2007 (2)	10,831	7,918	1,355	562	268	728
Year Ended December 31, 2006						
Revenues from third parties	$ 3,033	$ 1,743	$ 414	$ 115	$ 92	$ 669
Amount reclassified from AOCL (1)	(232)	(232)	-	-	-	-
Intersegment revenue	-	426	-	-	-	(426)
Income from equity method investees	139	-	139	-	-	-
Total Revenues	2,940	1,937	553	115	92	243
DD&A	633	552	24	9	14	34
Impairment of assets	9	9	-	-	-	-

Loss on derivative instruments	392	392	-	-	-	-
Income (loss) before income taxes	1,096	631	494	73	71	(173)
Equity method investments	373	-	373	-	-	-
Additions to long-lived assets	1,895	1,456	46	336	15	42
Total assets at December 31, 2006 (2)	9,589	7,225	961	343	257	803

(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) The US reporting unit includes goodwill of $759 million at December 31, 2008, $761 million at December 31, 2007, and $781 million at December 31, 2006.

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Note 16 – Additional Shareholders' Equity Information

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

	Year Ended December 31, 2008	2007
Common stock shares issued		
Shares, beginning of period	190,814,309	188,808,087
Exercise of common stock options	1,080,116	1,479,040
Restricted stock awards, net of forfeitures	402,339	527,182
Shares, end of period	192,296,764	190,814,309
Treasury stock		
Shares, beginning of period	18,580,865	16,574,384
Shares received from employees in payment of withholding taxes due on vesting of shares of restricted stock	32,544	-
Shares purchased pursuant to share buyback program	-	2,006,481
Shares, end of period	18,613,409	18,580,865

During 2007, we completed a $500 million common stock repurchase program begun in 2006.

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 (in millions)	Total
December 31, 2005	$ (764)	$ (20)	$ (784)
Cash flow hedges			
Realized amounts reclassified into earnings	145	1	146
Unrealized change in fair value	250	-	250
Unrealized amounts reclassified into earnings	265	-	265
Net change in minimum pension liability and other	-	16	16
Adoption of SFAS 158	-	(33)	(33)
December 31, 2006	(104)	(36)	(140)
Cash flow hedges			
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)

All amounts in the table above are reported net of tax. The effective income tax rate applied to AOCL increased from 35% at December 31, 2005 to 37.6% at December 31, 2006 and remained 37.6% at December 31, 2007 and 2008.

Note 17 – Commitments and Contingencies

Purchaser Bankruptcy – We have 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.

As of December 31, 2008, we had a receivable of approximately $71 million from SemCrude. We have determined that it is probable that a portion of the receivable is uncollectible. Therefore, during third quarter 2008, we reduced the carrying value of the SemCrude receivable and recognized a pre-tax charge of $38 million for the probable loss.

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We are pursuing various legal remedies to protect our interests. We believe that ultimate disposition of this matter will not have a material adverse affect on our financial position, results of operations, or cash flows.

Legal Proceedings – We are among a group of 18 defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930's. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. Dore has delivered documents alleging approximately $140 million in damages. Trial is currently set for April 27, 2009. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our financial position, results of operations, or cash flows.

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 properties. Rental expense for office buildings and oil and gas operations equipment was approximately $20 million in 2008, $13 million in 2007, and $12 million in 2006.

Minimum commitments as of December 31, 2008 consist of the following:

	Drilling, Equipment, and Purchase Obligations	Throughput Agreement	Transportation and Gathering (in millions)	Operating Lease Obligations	Total
2009	$ 485	$ 14	$ 12	$ 12	$ 523
2010	439	19	9	10	477
2011	399	19	8	8	434
2012	72	19	5	7	103
2013	-	19	5	1	25
2014 and thereafter	-	5	4	18	27
Total	$ 1,395	$ 95	$ 43	$ 56	$ 1,589

Note 18 – Recently Issued Pronouncements

SFAS 141(R) and SFAS 160 – In 2007, the FASB issued SFAS No. 141(R), "Business Combinations" (SFAS 141(R)) and SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160). These statements 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. Both statements are effective for periods beginning on or after December 15, 2008. SFAS 141(R) will be applied to business combinations occurring after the effective date and SFAS 160 will be applied prospectively to all noncontrolling interests, including any that arose before the effective date. We adopted SFAS 141(R) and SFAS 160 as of January 1, 2009. There were no non-controlling interests at adoption date. Adoption had no effect on our financial position and results of operations.

Adoption of SFAS 159—In 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 was effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We adopted SFAS 159 as of January 1, 2008. Adoption 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.

SFAS 161 – In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161). SFAS 161 amends and expands the disclosure requirements of SFAS 133 and requires 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. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS 161 as of January 1, 2009. The statement provides only for enhanced disclosures. Therefore, adoption had no impact on our financial position or results of operations.

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FSP FAS 132(R) – In December 2008, the FASB issued FSP FAS 132(R), "Employers' Disclosures About Postretirement Benefit Plan Assets" (FSP FAS 132(R)). FSP FAS 132(R) requires 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. The requirements apply to entities that are subject to the disclosure requirements of FAS 132R. Disclosures are to 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 FSP FAS 132(R) as of January 1, 2009. The statement provides only for enhanced disclosures. Therefore, adoption had no impact on our financial position or results of operations.

EITF 08-06– In November 2008, the FASB ratified the consensus reached in EITF 08-06, "Equity Method Investment Accounting Considerations" (EITF 08-06). EITF 08-06 was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of FAS 141(R). EITF 08-06 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, EITF 08-06 clarifies that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. EITF 08-06 is effective for fiscal years beginning on or after December 15, 2008. We adopted EITF 08-06 as of January 1, 2009. Adoption had no effect on our financial position and results of operations.

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Supplemental Oil and Gas Information (Unaudited)

In accordance with SFAS No. 69, “Disclosures about Oil and Gas Producing Activities” (SFAS 69), and regulations of the SEC, we are making the following supplemental disclosures about our crude oil and natural gas exploration and production operations.

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.

Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the vice president in charge of corporate reserves and certain members of senior management. During each of the years 2008, 2007 and 2006, we retained Netherland, Sewell & Associates, Inc. (NSAI), independent third-party reserve engineers, to perform reserve audits of proved reserves. The reserve audit for 2008 included a detailed review of 18 of our major international, deepwater Gulf of Mexico and US onshore fields, which covered approximately 79% of US proved reserves and 97% of international proved reserves (86% of total proved reserves). The reserve audit for 2007 included a detailed review of 16 of our major international, deepwater Gulf of Mexico and US onshore fields, which covered approximately 71% of US proved reserves and 96% of international proved reserves (81% of total proved reserves). The reserve audit for 2006 included a detailed review of 14 of our major international, deepwater Gulf of Mexico and US onshore fields, which covered approximately 80% of our total proved reserves. See Items 1 and 2. Business and Properties—Proved Reserves.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

Our supplemental disclosures are grouped by geographic area and include the United States, West Africa (Equatorial Guinea and Cameroon), Israel, Ecuador, North Sea and Other International (Argentina, China and Suriname). Operations in Equatorial Guinea, Cameroon, Ecuador, China, Cyprus and Suriname are conducted in accordance with the terms of production sharing contracts. Operations in other foreign locations are conducted in accordance with concession agreements or licenses.

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

Reserve 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.

Reserve Audit. The process involving an independent third-party engineering firm’s visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm’s complete external preparation of reserve estimates.

The following definitions apply to our categories of proved reserves:

Proved Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved Developed 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.

Proved Undeveloped 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)(2), (3) and (4).

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Supplemental Oil and Gas Information (Unaudited)

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

- Commodity Prices - Economic producibility of reserves and discounted cash flows will be 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 Reserve Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered.
- Reserve Estimation Using New Technologies - Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserve Personnel and Estimation Process - Additional disclosure is required regarding the qualifications of the chief technical person who oversees our reserves estimation process. We will also be 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 will expand and focus on the marketable product rather than the method of extraction.

The rules are effective for fiscal years ending on or after December 31, 2009, and early adoption is not permitted. We are currently evaluating the new rules and assessing the impact they will have on our reported oil and gas reserves. The SEC is coordinating with the Financial Accounting Standards Board to obtain the revisions necessary to SFAS 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies”, and SFAS 69 to provide consistency with the new rules. In the event that consistency is not achieved in time for companies to comply with the new rules, the SEC will consider delaying the compliance date.

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Proved Oil Reserves (Unaudited)

The following reserve schedule was developed by our reserve engineers and sets forth the changes in estimated quantities of proved crude oil reserves:

	Crude Oil, Condensate and NGLs (MMBbls)				
	United States	West Africa	North Sea	Other Int'l (1)	Total
Proved reserves as of:					
December 31, 2005	152	101	20	18	291
Revisions of previous estimates	-	(2)	-	-	(2)
Extensions, discoveries and other additions (2)	23	-	-	2	25
Purchase of minerals in place (3)	19	-	-	-	19
Sale of minerals in place (4)	(7)	-	-	-	(7)
Production (5)	(17)	(9)	(1)	(3)	(30)
December 31, 2006	170	90	19	17	296
Revisions of previous estimates (6)	28	-	1	-	29
Extensions, discoveries and other additions (7)	27	-	10	-	37
Purchase of minerals in place	-	-	-	-	-
Sale of minerals in place	(2)	-	-	-	(2)
Production (5)	(16)	(8)	(5)	(2)	(31)
December 31, 2007	207	82	25	15	329
Revisions of previous estimates (8)	(10)	1	-	-	(9)
Extensions, discoveries and other additions (9)	16	-	2	9	27
Purchase of minerals in place	3	-	-	-	3
Sale of minerals in place (10)	-	-	-	(7)	(7)
Production (5)	(18)	(8)	(4)	(2)	(32)
December 31, 2008	198	75	23	15	311
Proved developed reserves as of:					
December 31, 2005	114	101	8	16	239
December 31, 2006	115	90	19	16	240
December 31, 2007	129	71	15	14	229
December 31, 2008	121	57	15	6	199

(1) Other International includes China and Argentina. We sold our assets in Argentina in 2008.
(2) The increase in US proved reserves includes 14 MMBbl in the US Wattenberg field, primarily due to infill drilling activities.
(3) Purchase of minerals in place includes 18 MMBbl acquired in the purchase of U.S. Exploration. See Note 4—Acquisitions and Divestitures.
(4) Sale of minerals in place is primarily due to the sale of Gulf of Mexico shelf properties. See Note 4—Acquisitions and Divestitures.
(5) West Africa production includes sales from the Alba field to the Alba LPG plant of 3 MMBbl in 2008, 3 MMBbl in 2007, and 3 MMBbl in 2006.
(6) The 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.

(7) The 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.

(8) The 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.

(9) The increase in proved reserves includes 13 MMBbl in the US Wattenberg field, primarily due to infill drilling activities, and 9 MMBbl in China.

(10) Decrease due to sale of our assets in Argentina. See Note 4 – Acquisitions and Divestitures.

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Proved Gas Reserves (Unaudited)

The following reserve schedule was developed by our reserve engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (Bcf)					
	United States	West Africa	Israel	Ecuador	Other Int'l (1)	Total
Proved reserves as of:						
December 31, 2005	1,641	901	394	144	11	3,091
Revisions of previous estimates (2)	(83)	58	-	33	11	19
Extensions, discoveries and other additions (3)	314	-	-	-	-	314
Purchase of minerals in place (4)	141	3	-	-	-	144
Sale of minerals in place (5)	(110)	-	-	-	-	(110)
Production	(164)	(17)	(34)	(9)	(3)	(227)
December 31, 2006	1,739	945	360	168	19	3,231
Revisions of previous estimates (6)	(67)	44	-	29	(1)	5
Extensions, discoveries and other additions (7)	316	-	-	-	3	319
Purchase of minerals in place	3	-	-	-	-	3
Sale of minerals in place	-	-	-	-	-	-
Production	(151)	(48)	(41)	(9)	(2)	(251)
December 31, 2007	1,840	941	319	188	19	3,307
Revisions of previous estimates (8)	(253)	34	1	-	8	(210)
Extensions, discoveries and other additions (9)	345	78	4	-	-	427
Purchase of minerals in place (10)	72	-	-	-	-	72
Sale of minerals in place	-	-	-	-	-	-
Production	(145)	(75)	(51)	(8)	(2)	(281)
December 31, 2008	1,859	978	273	180	25	3,315
Proved developed reserves as of:						
December 31, 2005	1,279	431	337	144	11	2,202
December 31, 2006	1,255	360	303	168	19	2,105
December 31, 2007	1,259	830	263	188	16	2,556
December 31, 2008	1,268	700	216	180	21	2,385

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

(2) West Africa's positive revisions are primarily due to additional production allowances related to LNG sales. Positive revisions in Ecuador are related to better than expected well performance.

(3) The increase in US proved reserves includes 140 Bcf in the Wattenberg field, 77 Bcf in the Piceance basin and 55 Bcf in the Mid-continent area, primarily due to infill drilling activities.

(4) Purchase of minerals in place includes 128 Bcf acquired in the purchase of U.S. Exploration. See Note 4—Acquisitions and Divestitures.

(5)

Sale of minerals in place is primarily due to sale of Gulf of Mexico shelf properties. See Note 4—Acquisitions and Divestitures.

(6) The 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. West Africa's positive revisions are primarily due to additional production allowances related to LNG sales. Positive revisions in Ecuador are related to better than expected well performance.

(7) The 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.

(8) 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 oil reserves table as NGLs. West Africa's positive revisions are primarily due to additional production allowances related to LNG sales.

(9) The increase in US proved reserves includes 106 Bcf in the Wattenberg field and 173 Bcf in the Rockies, primarily from 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.

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

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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:

	United States	West Africa	Israel	Ecuador (in millions)	North Sea	Other Int'l (1)	Total
Year Ended December 31, 2008							
Revenues							
Sales (2)	$ 2,459	$ 500	$ 157	$ -	$ 410	$ 125	$ 3,651
Sales to affiliated power plant	-	-	-	30	-	-	30
Total Revenues	2,459	500	157	30	410	125	3,681
Production costs (3)	470	42	12	12	66	45	647
Exploration expense	111	9	4	1	18	39	182
DD&A	653	34	23	9	55	11	785
Impairment of assets	224	-	-	-	-	-	224
Income before income taxes	1,001	415	118	8	271	30	1,843
Income tax expense	339	99	22	2	132	17	611
Results of operations (4)	$ 662	$ 316	$ 96	$ 6	$ 139	$ 13	$ 1,232
Equity investee results of operations (5)	$ -	$ 118	$ -	$ -	$ -	$ -	$ 118
Year Ended December 31, 2007							
Revenues							
Sales (2)	$ 1,952	$ 406	$ 113	$ -	$ 364	$ 131	$ 2,966
Sales to affiliated power plant	-	-	-	35	-	-	35
Total Revenues	1,952	406	113	35	364	131	3,001
Production costs (3)	390	42	10	6	52	49	549
Exploration expense	122	44	1	-	17	3	187
DD&A	595	25	18	11	81	20	750
Impairment of assets	4	-	-	-	-	-	4
Income before income taxes	841	295	84	18	214	59	1,511
Income tax expense	191	84	14	4	114	10	417
Results of operations (4)	$ 650	$ 211	$ 70	$ 14	$ 100	$ 49	1,094
Equity investee results of operations (5)	$ -	$ 128	$ -	$ -	$ -	$ -	$ 128
Year Ended December 31, 2006							
Revenues							
Sales (2)	$ 1,937	$ 414	$ 92	$ -	$ 115	$ 143	$ 2,701
Sales to affiliated power plant	-	-	-	34	-	-	34

Total Revenues	1,937	414	92	34	115	143	2,735
Production costs (3)	420	32	9	6	22	42	531
Exploration expense	113	7	-	-	11	12	143
DD&A	571	23	14	12	9	26	655
Impairment of assets	9	-	-	-	-	-	9
Income before income taxes	824	352	69	16	73	63	1,397
Income tax expense	313	125	20	4	42	23	527
Results of operations (4)	$ 511	$ 227	$ 49	$ 12	$ 31	$ 40	$ 870
Equity investee results of operations (5)	$ -	$ 101	$ -	$ -	$ -	$ -	$ 101

(1) Other International includes China, Argentina (through February 2008) and Suriname.

(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 oil and gas operations expense, production and ad valorem taxes, transportation costs, 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.

(5) Equity investee results of operations represents our share of the Alba Plant equity investee results of operations from oil and gas producing activities.

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

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

	United States	West Africa	Israel	Ecuador (in millions)	North Sea	Other Int'l (2)	Total
Year Ended December 31, 2008							
Property acquisition costs							
Proved (3)	$ 256	$ -	$ -	$ -	$ -	$ -	$ 256
Unproved (4)	296	-	-	-	1	5	302
Total acquisition costs	552	-	-	-	1	5	558
Exploration costs	322	110	28	1	17	39	517
Development costs (5) (6) (7)	1,106	41	13	1	94	10	1,265
Total consolidated operations	$ 1,980	$ 151	$ 41	$ 2	$ 112	$ 54	$ 2,340
Our share of Alba Plant development costs	$ -	$ 2	$ -	$ -	$ -	$ -	$ 2
Year Ended December 31, 2007							
Property acquisition costs							
Proved	$ 11	$ -	$ -	$ -	$ -	$ -	$ 11
Unproved	145	-	-	-	-	1	146
Total acquisition costs	156	-	-	-	-	1	157
Exploration costs	184	179	2	-	52	3	420
Development costs (5) (6) (7)	1,081	15	25	-	47	23	1,191
Total consolidated operations	$ 1,421	$ 194	$ 27	$ -	$ 99	$ 27	$ 1,768
Our share of Alba Plant development costs	$ -	$ 1	$ -	$ -	$ -	$ -	$ 1
Year Ended December 31, 2006							
Property acquisition costs							
Proved (8)	$ 514	$ 8	$ -	$ -	$ -	$ -	$ 522
Unproved (8)	157	26	1	-	1	-	185
Total acquisition costs	671	34	1	-	1	-	707
Exploration costs	205	13	-	-	18	11	247
Development costs (5) (6) (7)	785	7	14	-	231	22	1,059
Total consolidated operations	$ 1,661	$ 54	$ 15	$ -	$ 250	$ 33	$ 2,013
Our share of Alba Plant development costs	$ -	$ 1	$ -	$ -	$ -	$ -	$ 1

(1) Costs incurred include capitalized and expensed items.
(2) Other International includes China, Argentina (through February 2008), Suriname and other new ventures.
(3) Includes $254 million related to the Mid-continent acquisition.
(4) Includes $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) US development costs include increases in asset retirement obligations of $34 million in 2008, $24 million in 2007, and $4 million in 2006. US asset retirement costs of $33 million in 2006 were incurred as a result of hurricane damage and are excluded from the costs incurred schedule above as we recovered the costs from insurance proceeds.
(6) Worldwide development costs include amounts spent to develop proved undeveloped reserves of $1.0 billion in both 2008 and 2007, and $768 million in 2006. Worldwide development costs also include $191 million spent on an FSPO in the North Sea Dumbarton field in 2006.
(7) North Sea development costs include increases in asset retirement obligations of $18 million in 2008 and $4 million in 2007.
(8) Includes amounts allocated from the U.S. Exploration acquisition (2006) See Note 4—Acquisitions and Divestitures.

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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, 2008	December 31, 2007
	(in millions)	
Unproved oil and gas properties (1)	$ 961	$ 1,165
Proved oil and gas properties (2)	10,905	8,903
Total oil and gas properties	11,866	10,068
Accumulated DD&A	(3,022)	(2,281)
Net capitalized costs	$ 8,844	$ 7,787
Our share of Alba Plant net capitalized costs	$ 113	$ 117

(1) Unproved oil and gas properties includes $465 million and $628 million at December 31, 2008 and 2007, 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 $180 million and $91 million at December 31, 2008 and 2007, respectively.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2008, 2007 and 2006 in accordance with SFAS 69. The standard requires the use of a 10% discount rate. This information is not the fair market value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves.

	United States	West Africa	Israel	Ecuador (in millions)	North Sea	Other Int'l (1)	Total
December 31, 2008							
Future cash inflows (2)	$ 16,551	$ 3,277	$ 938	$ 674	$ 1,170	$ 455	$ 23,065
Future production costs (3)	4,646	784	120	249	442	185	6,426
Future development costs	3,082	62	160	17	184	148	3,653
Future income tax expense	2,594	774	173	119	305	49	4,014
Future net cash flows	6,229	1,657	485	289	239	73	8,972
10% annual discount for estimated timing of cash flows	3,180	608	106	157	14	43	4,108
Standardized measure of discounted future net cash flows	$ 3,049	$ 1,049	$ 379	$ 132	$ 225	$ 30	$ 4,864
December 31, 2007							
Future cash inflows (2)	$ 30,733	$ 6,935	$ 858	$ 704	$ 2,492	$ 879	$ 42,601
Future production costs (3)	5,936	1,112	180	174	516	335	8,253
Future development costs	3,136	202	88	12	200	15	3,653
Future income tax expense	6,622	1,348	146	115	881	125	9,237
Future net cash flows	15,039	4,273	444	403	895	404	21,458
10% annual discount for estimated timing of cash flows	7,398	1,705	163	227	221	93	9,807
Standardized measure of discounted future net cash flows	$ 7,641	$ 2,568	$ 281	$ 176	$ 674	$ 311	$ 11,651
December 31, 2006							
Future cash inflows (2)	$ 18,948	$ 4,904	$ 972	$ 629	$ 1,225	$ 808	$ 27,486
Future production costs (3)	4,551	738	146	162	327	187	6,111
Future development costs	2,846	80	90	12	35	28	3,091
Future income tax expense	3,422	1,348	187	130	435	177	5,699
Future net cash flows	8,129	2,738	549	325	428	416	12,585
10% annual discount for estimated timing of cash flows	3,966	1,132	215	170	95	120	5,698

Standardized measure of discounted future net cash flows	$ 4,163	$ 1,606	$ 334	$ 155	$ 333	$ 296	$ 6,887

(1) Other International includes China and Argentina. We sold our assets in Argentina in 2008.

(2) The standardized measure of discounted future net cash flows for 2008, 2007 and 2006 does not include cash flows relating to anticipated future methanol or electricity sales.

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

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Prices and Other Assumptions in Discounted Future Net Cash Flows (Unaudited)

Future cash inflows are computed by applying year-end prices, 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	West Africa	Israel	Ecuador	North Sea	Other Int'l (1)	Total
December 31, 2008							
Average crude oil price per Bbl	$ 36.62	$ 40.51	$ -	$ -	$ 45.17	$ 31.69	$ 37.97
Average natural gas price per Mcf	4.99	0.25	3.43	3.74	5.72	-	3.39
December 31, 2007							
Average crude oil price per Bbl	$ 88.00	$ 81.26	$ -	$ -	$ 93.79	$ 61.72	$ 85.62
Average natural gas price per Mcf	6.78	0.27	2.69	3.74	7.07	-	4.36
December 31, 2006							
Average crude oil price per Bbl	$ 57.02	$ 51.49	$ -	$ -	$ 57.81	$ 48.04	$ 54.87
Average natural gas price per Mcf	5.32	0.27	2.70	3.75	7.11	0.85	3.48

(1) Other International includes China at December 31, 2008, 2007 and 2006 and Argentina at December 31, 2007 and 2006.

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 year-end prices at December 31, 2008 would change the discounted future net cash flows before income taxes by approximately $187 million or $168 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 $745 million in 2009, $795 million in 2010 and $541 million in 2011.

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,		
	2008	2007	2006
		(in millions)	

Imbalance receivables	$ 7	$ 13	$ 18
Imbalance liabilities	8	10	17

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

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Sources of Changes in Discounted Future Net Cash Flows (Unaudited)

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are as follows:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Standardized measure of discounted future net cash flows, beginning of year	$ 11,651	$ 6,887	$ 8,771
Changes in standardized measure of dicounted future net cash flows:			
Sales of oil and gas produced, net of production costs	(3,030)	(2,427)	(2,177)
Net changes in prices and production costs	(8,017)	5,266	(2,788)
Extensions, discoveries and improved recovery, less related costs	400	1,635	769
Changes in estimated future development costs	(883)	(775)	(558)
Development costs incurred during the period	1,291	1,189	1,076
Revisions of previous quantity estimates	(617)	1,276	(92)
Purchases of minerals in place	182	6	573
Sales of minerals in place	(66)	(95)	(579)
Accretion of discount	1,663	1,006	1,274
Net change in income taxes	2,853	(1,900)	777
Change in timing of estimated future production and other	(563)	(417)	(159)
Aggregate change in standardized measure of discounted future net cash flows	(6,787)	4,764	(1,884)
Standardized measure of discounted future net cash flows, end of year	$ 4,864	$ 11,651	$ 6,887

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Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended				
	March 31,	June 30,	September 30,	December 31,	Total
	(in millions except per share amounts)				
2008 (1)					
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 (4)	$ 1.25	$ (0.84)	$ 5.64	$ 1.77	$ 7.83
Diluted (2) (4)	1.20	(0.84)	5.37	1.72	7.58
2007 (3)					
Revenues	$ 743	$ 794	$ 814	$ 921	$ 3,272
Income before income taxes	304	293	344	427	1,368
Net income	212	209	223	300	944
Earnings per share:					
Basic (4)	$ 1.24	$ 1.22	$ 1.30	$ 1.75	$ 5.52
Diluted (4)	1.22	1.21	1.28	1.73	5.45

(1) First quarter 2008 includes the following:
- $237 million loss on commodity derivative instruments. (See Note 6–Derivative Instruments and Hedging Activities).

Second quarter 2008 includes the following:
- $828 million loss on commodity derivative instruments. (See Note 6–Derivative Instruments and Hedging Activities).

Third quarter 2008 includes 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);
- $38 million impairment of assets (See Note 4–Acquisitions and Divestitures); and
- $9 million loss on involuntary conversion (See Note 4–Acquisitions and Divestitures).

Fourth quarter 2008 includes the following:
- $630 million gain on commodity derivative instruments (See Note 6–Derivative Instruments and Hedging Activities); and
- $256 million impairment of assets (See Note 3–Asset Impairments).

(2) 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.

(3) First quarter 2007 includes the following:

- $13 million loss on involuntary conversion (See Note 4—Acquisitions and Divestitures).

Second quarter 2007 includes the following:

- $38 million loss on involuntary conversion (See Note 4—Acquisitions and Divestitures).

(4) 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.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities 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 effective.

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

We have been in the process of implementing a new Enterprise Resource Planning (ERP) software system to replace our various legacy systems. During 2008, we implemented additional phases of the system. As appropriate, we modified the design and documentation of internal control processes and procedures relating to the implementation of the newest phases. We believe that the new ERP system has strengthened and will continue to enhance our internal controls over financial reporting as additional phases are implemented; however, there are inherent risks in implementing any new system that could impact our financial reporting. See Item 1A. Risk Factors—Information technology systems implementation issues could disrupt our internal operations, increase our costs and adversely affect our financial results or our ability to report our financial results.

In the event that issues arise, we have manual procedures in place which would facilitate our continued recording and reporting of results from the new ERP system. However, 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.

We will continue to monitor, test, and appraise the impact and effect of the new ERP system on our internal controls and procedures as additional phases and features of the system are implemented. 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, except as described above.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2008.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2008.

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 2009 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2008.

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

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2008.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2008.

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.

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SIGNATURES

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

	NOBLE ENERGY, INC. (Registrant)
Date: February 19, 2009	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, President, Chief Executive Officer and Director
Date: February 19, 2009	By: /s/ Chris Tong Chris Tong, Senior Vice President, Chief Financial Officer
Date: February 19, 2009	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, President, Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2009
/s/ Chris Tong Chris Tong	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 19, 2009
/s/ Frederick B. Bruning Frederick B. Bruning	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 19, 2009
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 19, 2009
/s/ Michael A. Cawley Michael A. Cawley	Director	February 19, 2009
/s/ Edward F. Cox Edward F. Cox	Director	February 19, 2009
/s/ Thomas J. Edelman	Director	February 19, 2009

Thomas J. Edelman

/s/ Eric P. Grubman Eric P. Grubman	Director	February 19, 2009
s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 19, 2009
/s/ Scott D. Urban Scott D. Urban	Director	February 19, 2009
/s/ William T. Van Kleef William T. Van Kleef	Director	February 19, 2009

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INDEX TO EXHIBITS

Exhibit Number	Exhibit**
3.1	— Certificate of Incorporation, as amended through May 16, 2005, of the Registrant, filed herewith.
3.2	— By-Laws of Noble Energy, Inc. as amended through December 9, 2008 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 9, 2008) filed December 15, 2008 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 October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7 1/4% Notes Due 2023, including form of the Registrant's 7 1/4% 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).
4.4	— 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).
4.5	— 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).
4.6	— 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 7 1/4% 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).
4.7	— Third Indenture Supplement relating to $200 million of the Registrant's 5.25% 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 herewith.

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 herewith.

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 — Guaranty of the Registrant dated October 28, 1982, guaranteeing certain obligations of Samedan (filed as Exhibit 10.12 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference).

10.8* — 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).

10.9 — 364-day Credit Agreement dated as of November 27, 2002 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Citibank, N.A., Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).

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INDEX TO EXHIBITS

Exhibit Number	Exhibit**
10.10	— 364-day Credit Agreement dated as of October 30, 2003 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).
10.11	— Term Loan Agreement dated as of January 30, 2004 among Noble Energy Mediterranean Ltd., as borrower, Sumitomo Mitsui Banking Corporation, as initial lender and agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.12	— Guaranty of the Company dated January 30, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated January 30, 2004 (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.13	— Term Loan Agreement dated as of February 2, 2004 among Noble Energy Mediterranean Ltd., as borrower, Bank One, NA, as agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.14	— Guaranty of the Company dated February 2, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 2, 2004 (filed as Exhibit 99.4 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.15	— Term Loan Agreement dated as of February 4, 2004 among Noble Energy Mediterranean Ltd., as borrower, The Royal Bank of Scotland Finance (Ireland), as agent for the lenders and as the initial lender (filed as Exhibit 99.5 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.16	— Guaranty of the Company dated February 4, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 4, 2004 (filed as Exhibit 99.6 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.17*	— Form of Performance Units Agreement under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (filed as Exhibit 10.3 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).
10.18	— $2.1 billion Five-Year Credit Agreement, dated December 9, 2005, 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. and Citibank, N.A., 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: December 9, 2005), filed December 14, 2005 and incorporated herein by reference).
10.19	— $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).
10.20*	— Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009, filed herewith.
10.21*	— Consulting Agreement, dated May 9, 2005 but commencing May 16, 2005, by and between Noble Energy, Inc. and Thomas J. Edelman (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: May 16, 2005), filed May 20, 2005 and incorporated herein by reference).
10.22*	— 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).
10.23*	— 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).
10.24*	— 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).
10.25*	— Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan entered into by certain executive officers and key employees of the Company on May 16, 2005 and August 1, 2005, respectively (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein

by reference).

10.26*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 24, 2007), (filed as exhibit 10.1 to Registrant's Current Report on Form 8-K (Date of Event: April 24, 2007) filed April 30, 2007 and incorporated herein by reference).

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INDEX TO EXHIBITS

Exhibit Number		Exhibit**
10.27*	—	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).
10.28*	—	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).
10.29*	—	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).
10.30*	—	Amendment to the 2006 Performance Units Agreement (as amended effective January 1, 2008), (filed as Exhibit 10.43 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.31*	—	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2009), filed herewith.
10.32*	—	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).
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.
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).
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).
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).
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).
99.1	—	Report of Independent Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
99.2	—	Report of Netherland, Sewell & Associates, Inc., filed herewith.

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Senior Vice President and Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

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GLOSSARY

In this report, the following abbreviations are used:

Bbl(s)	Barrel(s)
MBbls	Thousand barrels
MMBbls	Million barrels
Bpd	Barrels per day
Bopd	Barrels oil 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
MMgal	Million gallons
KW	Kilowatt
KWh	Kilowatt hours
MW	Megawatt
GW	Gigawatt
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Tcf	Trillion cubic feet
Mcfpd	Thousand cubic feet per day
MMcfpd	Million cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcfe	Million cubic feet equivalent
Bcfe	Billion cubic feet equivalent
BTU	British thermal unit
MMBtu	Million British thermal units
MMBtupd	Million British thermal units per day
Btupcf	British thermal unit per cubic foot
MT	Metric tons
MTpd	Metric tons per day
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural gas liquid