NOBLE ENERGY INC
Form 10-K/A
May 20, 2008

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K/A

AMENDMENT NO. 1

(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, 2007
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 29, 2007: $10,563,558,607.
Number of shares of Common Stock outstanding as of February 12, 2008: 171,835,490.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2008 Annual Meeting of Stockholders held on April 22, 2008 are
incorporated by reference into Part III. Such definitive proxy statement was filed on March 21, 2008.

EXPLANATORY NOTE

We are filing this amendment to our annual report on Form 10-K for the year ended December 31, 2007, filed on February 27, 2008, to reflect changes made in response to comments we received from the staff of the Division of Corporation Finance of the Securities and Exchange Commission ("SEC") in connection with the staff's review of our annual report. This Amendment No. 1 on Form 10-K/A contains the complete text of Items 1 and 2, Item 1.A and Item 7, as amended. Unaffected Items have not been repeated in this Amendment No. 1.

Changes include the following:

- Expanded disclosure concerning both the general regulations as well as environmental regulations faced by us to specify the various regulatory bodies with which we interact and the specific laws and regulations to which we are subject, with several new paragraphs being added immediately after the original paragraph on "Government Regulation". See Items 1 and 2. Business and Properties —Government Regulation, pages 14-15.

- Revision of risk factors to focus on specific risks relating to us, with added disclosure to the risk factors on failure to fund continued capital expenditures; international operations; exploration, development and production; exploration and development drilling; acquisitions; governmental regulations; cost of drilling rigs; and competition. See Item 1A. Risk Factors, pages 17-22.

- Additional disclosure concerning the 2006 Equatorial Guinea Hydrocarbons Law. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Overview, page 23.

No attempt has been made in this Amendment No. 1 on Form 10-K/A to modify or update the other disclosures presented in the Form 10-K. This Amendment No. 1 on Form 10-K/A does not reflect events occurring after the filing of the Form 10-K or modify or update those disclosures. Accordingly, this Amendment No. 1 on Form 10-K/A should be read in conjunction with the Form 10-K and our other filings with the SEC.

Currently dated certifications from our Chief Executive Officer and Chief Financial Officer as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are filed herewith.

TABLE OF CONTENTS

PART I

Items 1 and 2. Business and Properties.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. 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 and natural gas since 1932. In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy and its subsidiaries. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which we have exploration rights. We operate throughout major basins in the United States (“US”) including Colorado’s Wattenberg field and Piceance basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. In addition, we conduct business internationally in China, Ecuador, the Mediterranean Sea, the North Sea, West Africa (Equatorial Guinea and Cameroon) and in other areas.

Strategy

We are a worldwide producer of crude oil and natural gas. 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 (Patina Oil & Gas Corporation (“Patina”) in 2005 and U.S. Exploration Holdings, Inc. (“U.S. Exploration”) in 2006), along with additional capital investment have resulted in substantial growth in the last five 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. Crude oil and natural gas sales volumes have doubled since 2003. Our reserve base, which includes both US and international sources at 58% US and 42% international, has almost doubled in the same period. We are now a larger, more diversified company with greater opportunities for both US and international growth. See Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2003-2007.

Proved Reserves

As of December 31, 2007, we had estimated proved reserves of 3.3 Tcf of natural gas and 329 MMBbls of crude oil. On a combined basis, these proved reserves were equivalent to 880 MMBoe, an increase of 5% over the prior year. At December 31, 2007, 74% of reserves were proved developed reserves.

Proved reserves estimates at December 31, 2007 were as follows:

	December 31, 2007		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States			
Natural gas (Bcf)	1,259	581	1,840
Crude oil (MMBbls)	129	78	207
Total US (MMBoe)	339	175	514
International			
Natural gas (Bcf)	1,297	170	1,467
Crude oil (MMBbls)	100	22	122
Total International (MMBoe)	316	50	366
Worldwide			
Natural gas (Bcf)	2,556	751	3,307
Crude oil (MMBbls)	229	100	329
Total Worldwide (MMBoe)	655	225	880

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 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Information (Unaudited) and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Reserves.

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 Director of Asset Development and certain members of senior management. During each of the years 2007, 2006 and 2005, 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 2007 included a detailed review of 16 of our major international, deepwater Gulf of Mexico and 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 US fields, which covered approximately 80% of our total proved reserves. The reserve audit for 2005 included a detailed review of 11 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 72% of our total proved reserves.

In connection with the 2007 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, 2007, based upon its evaluation. Its 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 that NSAI audits include our most significant fields and are chosen by senior engineering staff and division management with final approval by the Director of Asset Development and certain members of senior management. We usually include all deepwater Gulf of Mexico fields, all international fields that require reports by requirement of the host government, all fields that require sanctioning by our Board of Directors, and other major fields. No significant fields were excluded from the December 31, 2007 reserve audit.

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 21,966 MBoe above to 16,882 MBoe below as compared with our estimates. On a percentage basis, the NSAI field estimates ranged from 9% above our estimates to 42% 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, 2007, reserves differences, in the aggregate, were less than 13,200 MBoe, or 2%.

Since January 1, 2007, 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.

Acquisition and Divestiture Activities

We maintain an ongoing portfolio optimization program. 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.

In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Crude oil reserves for the Argentina properties totaled 7 MMBbls at December 31, 2007.

In 2006, we sold all of our Gulf of Mexico shelf properties except for the Main Pass area, which is undergoing redevelopment studies. 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 3—Acquisitions and Divestitures.

In 2006, we acquired U.S. Exploration, a privately held corporation, for $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located 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% of the reserves were proved developed and 55% of the reserves were natural gas. Proved crude oil and natural gas properties were valued at $413 million and unproved properties were valued at $131 million. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

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% of the reserves were proved developed and 67% of the reserves were natural gas. Proved crude oil and natural gas properties were valued at $2.6 billion and unproved properties were valued at $1.1 billion. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

3

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. We also own natural gas processing plants and natural gas gathering and other crude oil and natural gas related pipeline systems.

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 have significantly increased the breadth of our onshore operations, especially in the Rocky Mountain and Mid-continent areas. These two acquisitions have provided us with a multi-year inventory of exploitation and development opportunities. In 2007, we continued to expand our acreage position with the acquisition of approximately 290,000 net acres in the Piceance, Niobrara, and New Albany Shale areas. US operations accounted for 58% of our 2007 consolidated sales volumes and 58% of total proved reserves at December 31, 2007. Approximately 60% of the proved reserves are natural gas and 40% are crude oil. Our onshore US portfolio at December 31, 2007 included 1,308,823 gross developed acres and 1,234,858 gross undeveloped acres. We also hold interests in 97 offshore blocks in the Gulf of Mexico. In 2008, we plan to invest approximately $1.2 billion, or 74%, of budgeted capital in the US.

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

	Year Ended December 31, 2007 Sales Volumes			December 31, 2007 Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
Northern Region						
Wattenberg	59,670	4,674	14,619	893	109	258
Piceance	7,797	7	1,307	183	-	31
Niobrara	7,897	-	1,316	98	-	16
Other	9,392	53	1,618	139	1	24
Total	84,756	4,734	18,860	1,313	110	329
Southern Region						
Deepwater Gulf of Mexico	18,722	5,847	8,967	79	21	34
Mid-continent	30,760	3,340	8,467	341	51	108
Gulf Coast onshore and other	16,219	1,530	4,233	107	25	43
Total	65,701	10,717	21,667	527	97	185
Total United States	150,457	15,451	40,527	1,840	207	514

Additional information for our significant US operating areas is as follows:

	Year Ended December 31, 2007 Gross Wells Drilled/ Participated in	December 31, 2007 Gross Productive Wells
Northern Region		
Wattenberg	508	5,161
Piceance	55	112
Niobrara	125	744
Other	56	1,239
Total	744	7,256
Southern Region		
Deepwater Gulf of Mexico	6	13
Mid-continent	147	3,981
Gulf Coast onshore and other	38	457
Total	191	4,451
Total United States	935	11,707

Northern Region—The Northern region consists of our operations in the Rocky Mountain area, which includes the D-J (Wattenberg field), San Juan, Wind River, and Piceance basins, as well as the Niobrara, Bowdoin and Siberia Ridge fields. The addition of Patina and U.S. Exploration assets, particularly in the Wattenberg field, combined with our legacy operations in the Bowdoin field, the Niobrara trend, the Wind River basin and Piceance basin, have made the Rocky Mountains one of our core operating areas. We are currently running 13 drilling rigs and 24 completion/workover units. We plan to invest approximately $744 million, or 62% of budgeted US capital in the Northern region during 2008.

Wattenberg Field—The Wattenberg field (approximately 97% operated working interest), our largest US asset, continues to grow production and reserves. In 2007, sales of production from this field accounted for 36% of total US sales volumes. Wattenberg field proved reserves accounted for 50% of US proved reserves at December 31, 2007.

We acquired working interests in the Wattenberg field through the Patina Merger in 2005 and acquisition of U.S. Exploration in 2006. Located in the D-J basin of north central Colorado, the Wattenberg field provides us with a substantial future project inventory. 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, with 99.8% of the wells drilled in 2007 encountering sufficient quantities of reserves to be completed as economic producers. In May 1998, the Colorado Oil and Gas Conservation Commission (“COGCC”) adopted the “Greater Wattenberg Area Special Well Location Rule 318A” which allows all formations in the Wattenberg field to be drilled, produced and commingled from any or all of ten “potential drilling locations” on a 320-acre parcel. A “commingled” well is one which produces crude oil from two or more formations or zones through a common string of casing and tubing. In December 2005, the COGCC amended Rule 318A providing for an effective well density of one well per 20 acres in a designated portion of the Greater Wattenberg Area to more effectively drain the reservoir. The amendment applies only to the Niobrara, Codell and J-Sand formations and became effective in March 2006.

We are currently running seven drilling rigs and 17 completion units in the Wattenberg field. Our current field activities are focused primarily on the development of J-Sand, Codell and Niobrara 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. During 2007, we drilled or participated in 508 development wells, with a 99.8% success rate, and added approximately 244 Bcfe of proved reserves in the Wattenberg field. Approximately 58% of these reserve additions were natural gas. We also grew production from an average of 227 MMcfe per day for 2006 to 240 MMcfe per day for 2007. We plan to drill approximately 480 wells in 2008 (of which 337 will be combination Codell/Niobrara new drills). We also plan to participate in 120 non-operated drilling projects in 2008. We have a substantial project inventory remaining and plan to perform approximately 340 projects including refractures, trifractures, and recompletions during 2008.

Other Rocky Mountain areas include:

Niobrara Trend—The Niobrara trend (approximately 87% operated working interest) is located in eastern Colorado and extends into Kansas and Nebraska. During 2007, we expanded our acreage position with the acquisition of 160,000 net acres. We are currently running two drilling rigs and three completion units. During 2007, we drilled or participated in 125 wells with a 79% success rate, and our activity resulted in the addition of 19 Bcfe of proved reserves. We plan to drill 300 wells in 2008.

Piceance Basin—The Piceance basin in western Colorado (approximately 96% operated working interest) is another rapidly growing area for us. During 2007, we added 10,500 net acres to our position. We are currently running four drilling rigs and three completion units. We drilled or participated in 55 development wells during 2007, 100% of which were successful, and our activity resulted in the addition of 83 Bcfe of proved reserves. We plan to drill over 100 wells during 2008.

Other—We are also active in the Bowdoin field (approximately 60% operated working interest), located in north central Montana; the San Juan basin (approximately 81% operated working interest), located in northwestern New Mexico and southwestern Colorado; and the Wind River basin (approximately 56% operated working interest), located in central Wyoming. During 2007 we drilled or participated in a total of 56 development wells in these areas, 100% of which were successful. We plan to drill approximately 60 wells and recomplete 190 wells during 2008.

Southern Region—The Southern region includes the Gulf Coast onshore, West and East Texas, Louisiana, and the deepwater Gulf of Mexico, as well as the Mid-continent area (the Texas Panhandle and parts of Oklahoma, Kansas, Arkansas, Illinois and Indiana). The Gulf Coast and deepwater Gulf of Mexico are core US operating areas. During 2006, we sold all of our Gulf of Mexico shelf properties except for the Main Pass area. The sale of our shelf properties allows 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. We plan to invest approximately $460 million, or 38% of budgeted US capital, in the Southern region during 2008, with approximately 67% in the deepwater Gulf of Mexico, and the remainder to the Gulf Coast and the Mid-continent areas.

Deepwater Gulf of Mexico—Deepwater Gulf of Mexico accounted for 22% of 2007 US sales volumes and 7% of US proved reserves at December 31, 2007. During 2007, we continued to focus on the growth of our deepwater Gulf of Mexico business highlighted by a successful exploration discovery at Isabela and a successful sidetrack-appraisal well at our 2006 Raton discovery. We also completed successful development drilling programs in our Ticonderoga and Swordfish fields. Deepwater Gulf of Mexico activity resulted in proved reserve additions of 12 MMBoe during 2007. Participation in the 2007 Central Gulf of Mexico Outer Continental Shelf Sale resulted in our being awarded eight new deepwater Gulf of Mexico leases totaling $50 million.

At year-end, development planning was underway for Isabela (Mississippi Canyon Block 562, 33% working interest). We have also acquired an interest in adjacent acreage with additional exploration potential on Mississippi Canyon Blocks 519 and 563 (23.25% working interest). We plan to drill a well on Block 519 (Santa Cruz Prospect) in 2008 pending rig availability. In total there are three prospects on the combined leasehold that, conceptually, would be co-developed in a subsea tieback to an existing production facility.

Other 2007 exploration drilling included the Mississippi Canyon Block 568 #1 (Robusto Prospect, 20% working interest) and the East Breaks Block 465 #1 (Lost Ark South Prospect, 98.4% working interest), neither of which encountered hydrocarbons in commercial quantities.

During 2007 we saw an extremely active deepwater Gulf of Mexico development program. At our Raton project in Mississippi Canyon Block 248 (66.67% operated working interest), we successfully sidetracked and completed the 248 #1 discovery well drilled in 2006. At year-end the project had moved into the development stage and is slated for subsea tieback and first production in the second quarter of 2008.

At our operated Swordfish project (85% working interest), we drilled and completed a sidetrack to Viosca Knoll Block 917 #1 well and began gas production from this well at year end. At the Ticonderoga development in Green Canyon Block 768 (50% working interest, non-operated), the #3 and #1 ST4 wells were drilled and completed to extend and enhance production from the field. Both are slated for first production in the first quarter of 2008.

At the Lost Ark project in East Breaks Blocks 421 and 464 (48.4% operated working interest), the 421 #1 well, which had reached the end of its productive life, was plugged and abandoned, and the 464 #1 well was completed and put on production to develop the remaining reserves at the field.

We are currently evaluating a possible sidetrack-appraisal well to be drilled at the Raton South oil discovery in Mississippi Canyon Block 292 during late 2008 (originally drilled in 2006). The Redrock natural gas/condensate discovery, also drilled in 2006, is currently considered a co-development candidate to a successful sidetrack-appraisal well at Raton South. Additional key exploration activity planned for 2008 includes a well at the Mississippi Canyon Block 948, Gunflint prospect, (50% working interest), in the second half of 2008.

Mid-continent—A significant area of activity in Mid-continent is the Granite Wash development, located in the Texas Panhandle. We drilled or participated in 53 development wells in 2007, 100% of which were successful. The potential for horizontal drilling is currently being evaluated. Another significant area in Mid-continent is the ongoing Southern Oklahoma development. In 2007 we drilled or participated in 45 wells resulting in additional incremental production of 1,515 Boepd.

In addition, we continue to selectively increase our acreage position in resource plays, including shale plays. We have accumulated over 179,000 acres in the New Albany Shale. During 2007, we drilled 16 New Albany Shale wells. Currently nine are producing and seven are in the progress of pipeline connection. The Paxton facility, which we operate, will serve the majority of wells in the Paxton field. We plan to have an active drilling program during 2008.

Other Mid-continent areas include parts of Texas, Oklahoma, Kansas, Illinois, Indiana and Arkansas. During 2007, we drilled or participated in a total of 33 wells. We plan to drill or participate in 60 wells in the Mid-continent area during 2008.

Gulf Coast Onshore—During late 2007, we began a six well program at Oliver Creek in Shelby County, Texas to develop the Travis Peak reservoir as well as test deeper Cotton Valley horizons. We have completed one Travis Peak well and are currently completing the second Travis Peak well. The deeper Cotton Valley horizons are being tested in two additional wells currently being drilled or completed. Two additional wells remain in the current six well program. Additional drilling is planned for later in 2008.

International

International operations are significant to our business, accounting for 42% of consolidated sales volumes in 2007 and 42% of total proved reserves at December 31, 2007. International proved reserves are approximately 67% natural gas and 33% crude oil. Operations in Equatorial Guinea, Cameroon, Ecuador, China and Suriname are conducted in accordance with the terms of production sharing contracts. In 2008, we plan to invest approximately $392 million, or 24%, of budgeted capital in our international locations.

Additional information for our significant international operating areas is as follows:

	Year Ended December 31, 2007 Sales Volumes			December 31, 2007 Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
International						
West Africa	48,349	5,500	13,558	941	82	239
North Sea	2,276	4,564	4,943	19	25	28
Israel	40,449	-	6,742	319	-	53
Ecuador	9,385	-	1,564	188	-	31
China	-	1,402	1,402	-	8	8
Argentina	-	1,034	1,034	-	7	7
Total consolidated	100,459	12,500	29,243	1,467	122	366
Equity investees:						
Condensate (MBbls)	-	670	670			
LPG (MBbls)	-	2,135	2,135			
Total	100,459	15,305	32,048			
Equity investee share of methanol sales (Kgal)			160,540			

Wells drilled in 2007 and productive wells at December 31, 2007 in our international operating areas were as follows:

	Year Ended December 31, 2007 Gross Wells Drilled/Participated in	December 31, 2007 Gross Productive Wells
International		
West Africa	7	20
North Sea	2	22
Israel	1	8
Ecuador	-	5
China	-	16
Argentina	50	732
Total International	60	803

West Africa (Equatorial Guinea and Cameroon)—Operations in West Africa accounted for 46% of 2007 consolidated international sales volumes and 65% of international proved reserves at December 31, 2007. At December 31, 2007, we held 45,203 gross developed acres and 850,197 gross undeveloped acres in Equatorial Guinea and 1,125,000 gross undeveloped acres in Cameroon.

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 (located on Bioko Island), and an onshore LPG processing plant where additional condensate is produced. The methanol plant was originally designed to produce commercial grade methanol at a rate of 2,500 MTpd gross. As a result of various upgrade efforts, the plant is now 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 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 northwestern 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.

Our exploration activities in West Africa center around Blocks O and I offshore Equatorial Guinea and the PH-77 license offshore the Republic of Cameroon. We are the technical operator on Blocks O and I (45% and 40% working interest, respectively) and the operator on the PH-77 license (50% working interest). We drilled seven wells in the area during 2007 resulting in three new discoveries and three successful appraisal wells:

Benita – The I-1 well, testing the Benita prospect, resulted in a new gas-condensate discovery on Block I.

Benita appraisal – The I-2 appraisal well on Block I encountered crude oil. Testing has been deferred in order to secure an additional drilling rig that will be capable of further appraisal drilling downdip in the Benita oil column, which is in deeper water. It is expected that a rig will be available for drilling the additional Benita appraisal well in the first quarter of 2008.

Yolanda – The I-3 well, testing the Yolanda prospect, resulted in another new gas-condensate discovery on Block I.

I-4 – The I-4 well on Block I was a successful well on trend with the 2005 Belinda discovery on Block O.

Adriana – The O-2 exploration well (the Adriana Southwest prospect) on Block O offshore Equatorial Guinea did not contain commercial hydrocarbons. The well was plugged and abandoned.

Belinda appraisal – The O-3 appraisal well on Block O successfully extended the Belinda discovery by establishing significant downdip resources.

YoYo – The YoYo-1 well resulted in a new gas-condensate discovery on the PH-77 license offshore the Republic of Cameroon. Additional appraisal work is necessary to verify the areal extent of the discovery. There was also a secondary target, in which commercial hydrocarbons were not found.

In 2008, we plan to have an active exploration and appraisal drilling program for both Blocks I and O as we assess our options to commercialize our discoveries in the region.

Effective November 2006, the government of Equatorial Guinea enacted a new hydrocarbons law (the “2006 Hydrocarbons Law”) governing petroleum operations in Equatorial Guinea. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. At this time we are uncertain what economic impact this law will have on our operations in Equatorial Guinea.

North Sea—Operations in the North Sea (the Netherlands, Norway and the UK) comprise another core international asset, and we have been conducting business there since 1996. We have working interests in 23 licenses with working interests ranging from 7% to 100%. We are the operator of four blocks, covered by three licenses. The North Sea accounted for 17% of 2007 consolidated international sales volumes and 8% of international proved reserves at December 31, 2007. At December 31, 2007, we held 48,230 gross developed acres and 836,625 gross undeveloped acres.

In January 2007, production began at the non-operated Dumbarton development (30% working interest) in Blocks 15/20a and 15/20b in the UK sector of the North Sea. Dumbarton, a re-development of the Donan field, includes a subsea tie-back to the GP III, a floating production, storage and offloading vessel in which we own a 30% interest. We expect to continue the development of Dumbarton in 2008 with phases 2a and 2b. In addition, we will participate in the development of the Lochranza prospect, which will also consist of a subsea tie-back to the GP III.

Exploration efforts continued in 2007 as we and our partners successfully completed an exploratory appraisal well on the Flyndre Block (22.5% working interest) in the UK sector of the North Sea. We also participated in a successful exploration well at Selkirk in Block 22/22b P233 (30.5% working interest), also in the UK sector of the North Sea.

Mediterranean Sea (Israel)—Operations in Israel accounted for 23% of 2007 consolidated international sales volumes and 14% of international proved reserves at December 31, 2007. At December 31, 2007, we held 123,552 gross developed acres and 1,183,479 gross 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, and we are the operator.

We have been operating in the Mediterranean Sea, offshore Israel, since 1998, and our 47% working interest in the Mari-B field is one of our core international assets. The Mari-B field is the first offshore natural gas production facility in the State of Israel. During 2007, we completed the Mari-B #7, which is designed to produce twice what a normal Mari-B well produces in Israel, or approximately 200 MMcfpd of natural gas. The Mari-B#7 well has resulted in peak field deliverability of 600 MMcfpd.

Natural gas sales began in 2004 and have been increasing steadily as Israel's natural gas infrastructure has developed. In 2007, our gas sales volumes increased 19% over 2006 volumes and 67% over 2005 volumes. During 2007 we completed construction of a permanent onshore receiving terminal in Ashdod for distribution of natural gas from the Mari-B field to purchasers. Commissioning of the terminal is expected in early 2008. We also began selling natural gas to a desalinization plant and a paper mill in 2007. Additional natural gas sales in 2008 will depend on the timing of onshore pipeline construction and plant conversion, which should allow the Israel Electric Corporation Limited power plants at Gezer and Hagit to consume gas.

Exploration activities continue in Israel. We are in the process of securing a rig and intend to drill one exploration well testing the Tamar prospect (33% working interest), offshore northern Israel, in 2008.

Ecuador—Operations in Ecuador accounted for 5% of 2007 consolidated international sales volumes and 8% of international proved reserves at December 31, 2007. The concession covers 12,355 gross developed acres and 851,771 gross undeveloped acres.

We have been operating in Ecuador since 1996. We are currently utilizing the 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. During 2007, power generation totaled 911,830 MW hours.

Other International—Other international includes China, Argentina and Suriname.

We have been engaged in exploration and development activities in China since 1996 and production began in 2003. We are operator of the Cheng Dao Xi field (57% working interest), which is located in the shallow water of the southern Bohai Bay. During 2007, activities consisted primarily of workover projects. China accounted for 5% of 2007 consolidated international sales volumes and 2% of international proved reserves at December 31, 2007. At December 31, 2007, we held 7,413 gross developed acres and no undeveloped acres.

We continue to work with our Chinese partner (Shengli) to obtain governmental approval of the Supplemental Development Plan, designed to further develop the Cheng Dao Xi field through additional drilling and facilities construction.

Our producing properties in Argentina are located in southern Argentina in the El Tordillo field (13% working interest), which is characterized by secondary recovery crude oil production. During 2007, we participated in the drilling of 50 gross (6.7 net) development wells. Argentina accounted for 4% of 2007 consolidated international sales volumes and 2% of international proved reserves at December 31, 2007. At December 31, 2007, we held 113,325 gross developed acres and no undeveloped acres in Argentina.

In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Crude oil reserves for the Argentina properties totaled 7 MMBbls at December 31, 2007.

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 (60% working interest) and on Block 32 (100% working interest), which combined cover approximately 7.7 million gross acres offshore. We expect to participate in the drilling of one well on the West Tapir prospect on Block 30 in 2008.

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

	Sales Volumes (1)		Average Sales Price		Average Production Cost
	Natural Gas MMcf	Crude Oil MBbls	Natural Gas Per Mcf (2)	Crude Oil Per Bbl (2)	Per BOE (3)
Year Ended December 31, 2007					
United States	150,457	15,451	$ 7.51	$ 53.22	$ 8.49
West Africa (4) (5)	48,349	5,500	0.29	71.27	2.89
North Sea	2,276	4,564	6.54	76.47	9.81
Israel	40,449	-	2.79	-	1.14
Other International (6)	9,385	2,436	-	53.69	12.06
Total Consolidated Operations	250,916	27,951	5.26	60.61	6.99
Equity Investee (7)	-	2,805	-	55.09	
Total	250,916	30,756	$ 5.26	$ 60.10	
Year Ended December 31, 2006					
United States	164,875	16,715	$ 6.61	$ 50.68	$ 8.12
West Africa (4) (5)	16,579	6,519	0.37	62.51	2.86
North Sea	2,967	1,357	8.00	67.43	10.08
Israel	33,906	-	2.72	-	1.60
Other International (6)	9,041	2,752	0.96	52.05	9.74
Total Consolidated Operations	227,368	27,343	5.55	54.47	6.97
Equity Investee (7)	-	2,931	-	45.83	
Total	227,368	30,274	$ 5.55	$ 53.64	
Year Ended December 31, 2005					
United States	125,543	9,468	$ 7.43	$ 46.67	$ 7.39
West Africa (4) (5)	23,938	6,492	0.25	42.51	2.93
North Sea	3,394	1,964	5.93	52.68	7.54
Israel	24,228	-	2.68	-	2.11
Other International (6)	8,389	2,866	1.10	42.37	7.15
Total Consolidated Operations	185,492	20,790	5.78	45.35	6.06
Equity Investee (7)	-	1,183	-	43.43	
Total	185,492	21,973	$ 5.78	$ 45.25	

(1) 2007 volumes include the effect of crude oil sales less than volumes produced of 165 MBbls in Equatorial Guinea, 112 MBbls in the North Sea and 48 MBbls in other international. 2006 volumes include the effect of crude oil sales in excess of volumes produced of 195 MBbls in Equatorial Guinea, less than volumes produced of 99 MBbls in the North Sea, and in excess of volumes produced of 18 MBbls in other international. The variance between production from the field and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings. Sales volumes equal production volumes in 2005.

(2)

Average natural gas sales prices in the US reflect an increase of $1.12 per Mcf (2007), and reductions of $0.25 per Mcf (2006) and $0.77 per Mcf (2005) from hedging activities. Average crude oil sales prices for the US reflect reductions of $13.68 per Bbl (2007), $11.41 per Bbl (2006) and $8.03 per Bbl (2005) from hedging activities. Average crude oil sales prices for West Africa reflect reductions of $2.19 (2007) and $9.93 (2005) from hedging activities. We did not hedge West Africa crude oil sales in 2006.

(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 facility. 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. For 2007 and 2006, the price on an Mcf basis has been adjusted to reflect the Btu content of gas sales.

(5) Equatorial Guinea natural gas volumes include sales to the LNG facility of 78,090 Mcfpd for 2007. There were no natural gas sales to the LNG facility before 2007.

(6) Other International natural gas volumes include Ecuador and Argentina. Although Ecuador natural gas volumes are included in Other International production, they are excluded from average natural gas sales prices. We own 100% of the natural gas-to-power project in Ecuador and intercompany natural gas sales are eliminated. Natural gas production volumes associated with the gas-to-power project were 9,385 MMcf for 2007, 8,933 MMcf for 2006 and 8,321 MMcf for 2005. Other International oil includes China and Argentina.

(7) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 2,135 MBbls in 2007, 2,297 MBbls in 2006 and 850 MBbls in 2005.

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

At December 31, 2007, our operated properties accounted for approximately 62% 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, 2007 is as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States - Onshore	7,055	5,997.8	4,609	3,134.5	11,664	9,132.3
United States - Offshore	28	26.1	15	8.1	43	34.2
West Africa	1	0.4	19	7.2	20	7.6
North Sea	15	2.7	7	0.7	22	3.4
Israel	-	-	8	3.8	8	3.8
Ecuador	-	-	5	5.0	5	5.0
China	16	9.1	-	-	16	9.1
Argentina	732	95.4	-	-	732	95.4
Total	7,847	6,131.5	4,663	3,159.3	12,510	9,290.8
Multiple Completions	8	5.9	14	3.6	22	9.5

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. One or more completions in the same borehole are counted as one well in this table.

Developed and Undeveloped Acreage—Developed and undeveloped acreage (including both leases and concessions) held at December 31, 2007 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States				
Onshore	1,308,823	835,445	1,234,858	786,391
Offshore	147,945	94,963	485,258	227,627
Total United States	1,456,768	930,408	1,720,116	1,014,018
Equatorial Guinea	45,203	15,727	850,197	379,026
Cameroon	-	-	1,125,000	562,500
North Sea (1)	48,230	5,671	836,625	339,151
Israel	123,552	58,142	1,183,479	532,818
China	7,413	4,225	-	-
Ecuador	12,355	12,355	851,771	851,771
Argentina	113,325	15,548	-	-
Suriname	-	-	7,740,328	6,362,884
Total International	350,078	111,668	12,587,400	9,028,150
Total Worldwide (2)	1,806,846	1,042,076	14,307,516	10,042,168

(1) The North Sea includes acreage in the UK, the Netherlands and Norway. In 2008, we entered into an agreement, subject to regulatory approval, to sell our interest in the Norway acreage consisting of 411,065 gross (126,607 net) undeveloped acres.

(2) If production is not established, approximately 731,079 gross acres (433,236 net acres) will expire during 2008, 424,734 gross acres (193,554 net acres) will expire during 2009, and 683,274 gross acres (367,949 net acres) will expire during 2010.

Developed acreage includes leases that contain wells capable of production. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof. Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

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, 2007						
United States	14.2	4.5	18.7	757.6	27.6	785.2
West Africa	2.6	0.5	3.1	-	-	-
North Sea	0.5	-	0.5	-	-	-
Israel	-	-	-	0.4	-	0.4
Argentina	-	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	6.3	9.0	15.3	666.6	5.5	672.1
West Africa	-	0.4	0.4	1.8	-	1.8
North Sea	-	-	-	1.1	-	1.1
Argentina	-	-	-	7.6	-	7.6
Total	6.3	9.4	15.7	677.1	5.5	682.6
Year Ended December 31, 2005						
United States	4.7	10.7	15.4	488.1	25.9	514.0
West Africa	-	-	-	0.3	-	0.3
North Sea	-	0.2	0.2	-	-	-
Argentina	-	-	-	7.7	-	7.7
Total	4.7	10.9	15.6	496.1	25.9	522.0

(1) Does not include wells drilled but not yet completed.

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.

In addition to the wells drilled and completed during 2007 included in the table above, at December 31, 2007, we were drilling or completing 2 gross (1.0 net) development wells offshore US, 223 gross (192.3 net) development wells and 4 gross (3.3 net) exploratory wells onshore US and one gross (0.1 net) development well in Argentina.

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.

Natural gas produced in the US is sold predominately under short-term or long-term contracts at market-based prices. In Equatorial Guinea and Israel, we sell natural gas to end-users under long-term contracts at negotiated prices. During 2007, approximately 12% of natural gas sales were made pursuant to long-term contracts.

Crude oil and condensate produced in the US and foreign locations is 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. Crude oil and condensate are distributed through pipelines and by trucks or tankers to gatherers, transportation companies and refineries.

Significant Purchaser—Marathon Petroleum Supply Company (“Marathon”) was the largest single non-affiliated purchaser of 2007 production and purchased our share of condensate from the Alba field in Equatorial Guinea. Sales to Marathon accounted for 18% of 2007 crude oil sales, or 10% of 2007 total oil and gas sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2007. 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 remained volatile during 2007 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, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Regulations

Government Regulation—Exploration for, and production and sale 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, 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 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;

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the Department of Transportation, which has certain authority over the transportation of products, equipment and personnel necessary to our 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 Securities and Exchange Commission, 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. An example of such regulation on the operational side is 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. 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 for Business, Enterprise and Regulatory Reform. 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.

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 upon our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact upon 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 and natural gas 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 1,243 at December 31, 2006 to 1,398 at December 31, 2007. The 2007 year-end employee count includes 181 foreign nationals working as employees in Ecuador, China, Israel, the UK, Equatorial Guinea, Cameroon and Suriname.

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, Suriname 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 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.

In 2007, 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.

16

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. 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 producing 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 flow;
- 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;
- 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.

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 revenue 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 flow from operations is 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. If we are not able to fund our capital expenditures, interests in some properties might be reduced or forfeited as a result.

A recession or an economic slowdown 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. Currently, the US economy is slowing and may be headed toward a recession. A recession may lead to significant fluctuations in demand and pricing for our crude oil and natural gas production. If we were to continue development of our property interests after a decline in the prices of crude oil and natural gas had occurred, our profitability may be significantly affected by decreased demand and lower commodity prices. In addition, our future access to capital could be limited due to tightening credit markets.

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 42% of our consolidated sales volumes in 2007 coming from international operations. These operations may be adversely affected by political and economic developments, including the following:

- war, terrorist acts and civil disturbances, such as may occur in regions that encompass our operations in 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 value of the US dollar, such as the decline of the US dollar against the pound sterling given that some of our North Sea development expenditures are paid in pound sterling; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

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, 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 of them or do so 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.

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.

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 issue. 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 and Israel. As a result 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 have increased. 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 prudent. 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.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2007, we had long-term indebtedness of $1.9 billion (excluding unamortized discount), with $1.2 billion drawn under our bank credit facility. Our indebtedness represented 28% of our total book capitalization at December 31, 2007.

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;
- 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.

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 are currently 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 expect to implement additional phases during 2008. As a part of this effort, we are transitioning data and changing 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;
- 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” a 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.

PART II.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

We are an independent energy company engaged in the acquisition, exploration, development, production and marketing of crude oil and natural gas domestically and internationally. We operate throughout major basins in the US including Colorado's Wattenberg field and Piceance basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. We also conduct business internationally, in China, Ecuador, the Mediterranean Sea, the North Sea, West Africa (Equatorial Guinea and Cameroon) and in other areas.

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 flow through the development of a high quality portfolio of producing assets that is diversified between US and international projects. The Patina Merger, purchase of U.S. Exploration and sale of Gulf of Mexico shelf properties have allowed us to achieve a strategic objective of enhancing our US asset portfolio. The result is a company with assets and capabilities that include growing US basins coupled with a significant portfolio of international properties. Our reserve base includes both US and international sources at 58% US and 42% international. We are now a larger, more diversified company with greater opportunities for both US and international growth.

2007 was a strong year for us, both financially and operationally. Significant financial results included the following:

- net income of $944 million, a 39% increase over 2006 net income;
- diluted earnings per share of $5.45, a 44% increase over 2006;
- cash flow provided by operating activities of $2.0 billion, a 17% increase over 2006; and
- completion of a $500 million common stock repurchase program begun in 2006.

Significant operational highlights included the following:

- eight successful exploration wells drilled internationally, six offshore West Africa and two in the North Sea;
- deepwater Gulf of Mexico exploration success at Isabela (Mississippi Canyon Block 562);
- commencement of production and continued ramp-up at the Dumbarton development and successful exploratory appraisal well drilled at the Flyndre prospect in the UK sector of the North Sea;
- completion of the Mari-B #7 well and record natural gas sales in Israel;
- continued success of development program in the US Wattenberg field; and
- acquisition of approximately 290,000 net acres onshore US in the Piceance basin, Niobrara trend and New Albany Shale areas.

Sale of Argentina—In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008.

Equatorial Guinea 2006 Hydrocarbons Law—Effective November 2006, the government of Equatorial Guinea enacted the 2006 Hydrocarbons Law governing petroleum operations in Equatorial Guinea. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. The stated purpose of the law is to modify the legal framework in order to deal with a variety of matters that were not previously or adequately covered, with the law addressing areas such as minimum participation of the state in contract areas, training and social programs and the establishment of environmental programs. At this time we are uncertain what economic impact this law will have on our operations in Equatorial Guinea, as regulations contemplated by the law have not been implemented and the application of certain of the law's provisions is unknown.

2008 OUTLOOK

We expect crude oil and natural gas production to increase in 2008 compared to 2007. Factors which may impact our expected year-over-year increase in production include:

- higher sales of natural gas from the Alba field in Equatorial Guinea; and
- growing production from the D-J and Piceance basins, where we are continuing active drilling programs;

offset by:

- natural field decline in the Gulf Coast area.

Factors which may impact our expected production profile include:

- potential hurricane-related volume curtailments in the Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- infrastructure development in Israel;
- potential downtime at the methanol, LPG and/or LNG facilities in Equatorial Guinea;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project; and
- timing of capital expenditures, as discussed below, which are expected to result in near-term production.

2008 Budget—We have budgeted capital expenditures of approximately $1.6 billion for 2008. Approximately 24% of the 2008 capital budget has been allocated to exploration opportunities and 76% has been allocated to production, development and other projects. US spending is budgeted for $1.2 billion, international expenditures are budgeted for $392 million and corporate expenditures are budgeted for $27 million. The 2008 budget does not include the impact of possible asset purchases. We expect that the 2008 capital budget will be funded primarily from cash flows from operations and borrowings under our revolving credit facility. 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.

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.

Purchase Price Allocation—As a result of the Patina Merger in 2005 and the acquisition of U.S. Exploration 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 merger. 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.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on our cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to crude oil and natural gas properties result in higher future depreciation, depletion and amortization (“DD&A”) expense, which results in decreased future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher estimates of future crude oil and natural gas prices, could increase the likelihood of impairment in the event of lower commodity prices or higher operating or development costs 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, 2007, the consolidated balance sheet included $760 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 also 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.

The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. The fair value of the US reporting unit was determined using a combination of the income approach and the market approach. Under the income approach, the fair value of the reporting unit is estimated based on the present value of expected future cash flows. Under the market approach, the fair value is estimated based on selected financial metrics.

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 an impairment of all or a portion of goodwill in future periods. Under the market approach, we make certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although we have based the fair value estimate on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In 2007, no goodwill impairment was recognized.

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 our 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.

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. 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 trigger 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 trigger a goodwill impairment analysis.

Oil and Gas Properties—We account for crude oil and natural gas properties under the successful efforts method of accounting. The alternative method of accounting for crude oil and natural gas properties is the full cost method. 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 proved reserves and to drill and equip development wells are capitalized. Proved property acquisition costs are amortized to operations by the unit-of-production method on a property-by-property 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 operations by the unit-of-production method on a property-by-property basis. They are amortized based on proved developed crude oil and natural gas reserves. 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. Under the full cost method, these costs 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 as this method is better aligned with our business strategy. 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 will carry the costs of an exploratory well as an asset if the well 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 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. 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, 2007, the balance of property, plant and equipment included $249 million of suspended exploratory well costs, $62 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 5—Capitalized Exploratory Well Costs.

Impairment of Proved Oil and Gas Properties—We assess proved crude oil and natural gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital 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 and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate property impairment. We recorded approximately $4 million of impairments in 2007, primarily related to 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. 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 amounts 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 at a rate approximate to our cost of capital 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. During 2007, we recorded impairments of significant unproved oil and gas properties totaling approximately $3 million in exploration expense.

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. Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," requires that the discounted 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 must 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. See Item 8. Financial Statements and Supplementary Data—Note 6—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 and Katrina. 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. See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

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". For derivative instruments that qualify as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in accumulated other comprehensive income or loss ("AOCL") until the hedged forecasted transaction is recognized in earnings. Therefore, prior to settlement of the derivative instruments, changes in the fair market value of those derivative instruments can cause significant increases or decreases in AOCL. For derivative instruments that do not qualify as cash flow hedges, changes in fair value are reported in current period net income and therefore can result in significant increases or decreases in current period net income. All hedge ineffectiveness is recognized in the current period in net income. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction. Regression analysis is performed on initial assessment of the hedge and subsequently every quarter thereafter in order to determine that the hedge instrument will be or has been highly effective in offsetting gains or losses on the future transaction. As discussed in Item 8. Financial Statements and Supplementary Data—Note 2—Summary of Significant Accounting Policies, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments, effective January 1, 2008. Such a change did not affect our net assets or cash flows at December 31, 2007 and will not require adjustments to our previously reported financial statements. However, the use of mark-to-market accounting for our commodity derivatives will likely add volatility to our reported earnings. We occassionally 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. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivatives and Hedging Activities.

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.

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. Over the last three years, we have increased the allowance by approximately $40 million to cover potentially uncollectible balances related to the Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation. However, if estimates are inaccurate, we may incur gains or losses that could have a material effect on our results of operations.

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, 2007, cumulative asset gains 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 2007 net periodic benefit cost by approximately $1 million. The expected return assumption used for 2007 was 8.25%.

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, 2007 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 2007 net periodic benefit cost by $4 million and decreased the benefit obligation for the combined plans by $17 million at December 31, 2007. A 1% decrease in the discount rate assumption would have increased 2007 net periodic benefit cost by $5 million and increased the benefit obligation for the combined plans by $20 million at December 31, 2007. The assumed discount rate used to determine net periodic benefit cost for 2007 was 5.75%. The assumed discount rate used to determine the benefit obligations at December 31, 2007 was 6.5% for our defined benefit pension and restoration plans and 6.25% for our medical and life plans.

Effective January 1, 2008, the defined benefit pension plan and restoration plans were amended in order to provide a lump sum option. Certain assumptions were made regarding the percentage of active participants who would elect the lump sum option upon future termination and the percentage of existing deferred vested participants who would elect the lump sum option during 2008. In addition, the amounts of lump sum payments are affected by mortality and interest rate assumptions. The lump sum option increased the projected benefit obligation by $5.5 million at December 31, 2007 and will increase 2008 net periodic benefit cost by approximately $1 million.

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), as of December 31, 2006. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans.

Recently Issued Pronouncements—See Item 8. Financial Statements and Supplementary Data—Note 16—Recently Issued Pronouncements.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary cash needs are to fund capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings or to pay other contractual commitments and interest payments on debt and to pay dividends. Our traditional sources of liquidity are cash on hand, cash flows from operations and available borrowing capacity under credit facilities. Funds may also be generated from occasional sales of non-strategic crude oil and natural gas assets. We had $660 million in cash and cash equivalents at December 31, 2007, compared with $153 million at December 31, 2006. Substantially all of this cash is located in our foreign subsidiaries and would be subject to additional US income taxes if repatriated. The 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. We currently intend to use our international cash to fund international projects, including the development of West Africa.

We are monitoring the current conditions in the credit markets. 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 affected. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Our ratio of debt-to-book capital has decreased from 30% at December 31, 2006, to 28% at December 31, 2007. 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 include:

- a $75 million increase in total debt from the balance at December 31, 2006;
- a $944 million increase in shareholders' equity from current year net income;
- a $102 million decrease in shareholders' equity due to repurchase of common stock; and
- a $144 million decrease in shareholders' equity (effected by an increase in AOCL) primarily related to an increase in deferred hedging losses.

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Total cash provided by (used in):			
Operating activities	$ 2,016,573	$ 1,730,306	$ 1,239,878
Investing activities	(1,403,089)	(1,098,339)	(1,892,488)
Financing activities	(107,029)	(588,880)	583,137
Increase (decrease) in cash and cash equivalents	$ 506,455	$ 43,087	$ (69,473)

Operating Activities—Net cash provided by operating activities increased $286 million, or 17% during 2007 as compared with 2006. The increase was due primarily to higher average realized crude oil prices and higher average realized US natural gas prices. These increases were partially offset by higher exploration expense and general and administrative ("G&A") expense. In addition, cash flows from operating activities in 2007 included dividends from equity method investments, which had been classified as investing cash flows in 2006. See Results of Operations—Income from Equity Method Investees.

Net cash provided by operating activities increased $490 million, or 40%, during 2006 as compared with 2005. The increase was due primarily to higher sales volumes and higher average realized crude oil prices, offset by lower average realized US natural gas prices and increases in total production costs, G&A expense and interest expense.

Investing Activities—The primary use of cash in investing activities is for capital spending, which may be offset by proceeds from property sales or dividends from equity method investees. Net cash used in investing activities increased $305 million, or 28% during 2007 as compared with 2006. The change was due primarily to a decrease in divestiture activity in 2007 as compared with 2006, when we sold our Gulf of Mexico shelf properties. In addition, investing cash inflows were reduced in 2007 because distributions received from equity method investees were included in operating cash flows. See Results of Operations—Income from Equity Method Investees.

Net cash used in investing activities decreased $794 million, or 42% during 2006 as compared with 2005. The decrease was due primarily to a decrease in acquisition activity in 2006 as compared to the Patina Merger in 2005 and an increase in divestiture activity in 2006, due to the sale of our Gulf of Mexico shelf properties, which provided investing cash inflows in 2006.

Financing Activities—Net cash used in financing activities decreased $482 million during 2007 as compared with 2006. The change was due to net increases in the credit facility during 2007 as compared with payments being made to decrease outstanding debt during 2006. In 2007 there was also a net decrease of $297 million in amounts used to repurchase common stock as compared with 2006. Cash flows were provided by financing activities in 2005, as compared with 2006, and totaled $583 million. In 2005, cash was provided by borrowings under the credit facility and exercise of stock options, partially offset by dividend payments and the repayment of debt acquired in the Patina Merger.

Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Acquisition, Capital and Other Exploration Expenditures			
Lease acquisition of unproved property	$ 145,326	$ 53,652	$ 16,793
Exploration expenditures	371,758	203,035	161,515
Development expenditures	1,185,385	1,054,780	662,585
Corporate and other expenditures	36,361	35,069	21,478
Total consolidated capital expenditures	1,738,830	1,346,536	862,371
Our share of equity investee development costs	516	580	27,639
Total	$ 1,739,346	$ 1,347,116	$ 890,010

Total capital expenditures during 2007 increased $392 million, or 29%, as compared with 2006. The increase was due to lease acquisition in the US, 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. Total capital expenditures during 2006 increased $457 million, or 51%, as compared with 2005. The increase was primarily due to development expenditures in the US and the North Sea. Capital expenditures for 2005 included $275 million of post-merger exploration and development-related expenditures on Patina properties.

As a result of the U.S. Exploration acquisition in 2006, we allocated $413 million to proved properties and $131 million to unproved properties. As a result of the Patina Merger in 2005, we allocated $2.6 billion to proved properties and $1.1 billion to unproved properties.

Insurance Recoveries

See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

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 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 coverage only for claims in excess of $100 million, 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. Effective June 2007, we no longer carry business interruption insurance for our Gulf of Mexico operations.

Financing Activities

Long-Term Debt—Our long-term debt totaled $1.9 billion (excluding unamortized discount) at December 31, 2007. Maturities range from 2009 to 2097. Our principal source of liquidity is an unsecured revolving credit facility (the

“Credit Facility”). In November 2007, we extended 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 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. At December 31, 2007, the total debt to capitalization ratio was 28%, calculated for this purpose as total debt divided by the sum of total debt plus shareholders' equity.

The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes. At December 31, 2007, $1.2 billion in borrowings were outstanding under the Credit Facility. The weighted average interest rate applicable to borrowings under the Credit Facility at December 31, 2007 was 5.28%.

We also have $650 million of fixed-rate debt outstanding at December 31, 2007 with a weighted average interest rate of 6.92%. Maturities range from 2014 to 2097.

Installment Payments Due—During 2007, we purchased working interests in oil and gas properties in the Piceance basin of western Colorado for $75 million. After making an initial cash payment of $25 million, we owe $50 million in the form of installment payments to the seller. Installments of $25 million each are due on May 12, 2008 and May 11, 2009. The amount due in 2008 is included in short-term borrowings and the amount due in 2009 is included in long-term debt in the consolidated balance sheets. Interest on the unpaid amounts is due quarterly. Interest accrues at a LIBOR rate plus .30%. The interest rate was 5.53% at December 31, 2007.

Short-Term Borrowings—Our Credit Facility 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, there were no short-term borrowings outstanding at December 31, 2007.

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 which are scheduled to expire third quarter 2008. See Item 8. Financial Statements and Supplementary Data—Note 7—Debt.

Cash Interest Payments—We made cash interest payments, net of capitalized interest, of $105 million in 2007, $106 million in 2006 and $84 million in 2005.

Common Stock Repurchase Program—During 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 $101 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.

Dividends—We paid cash dividends totaling 43.5 cents per common share in 2007, 27.5 cents per common share in 2006 and 15 cents per common share in 2005. On January 22, 2008, the Board of Directors declared a quarterly cash dividend of 12.0 cents per common share, which was paid February 19, 2008 to shareholders of record on February 4, 2008. 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.

Exercise of Stock Options—Proceeds from the exercise of stock options totaled $25 million in 2007, $63 million in 2006 and $68 million in 2005. 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.

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, 2007, the material off-balance sheet arrangements and transactions that we have entered into included drilling service contracts, operating lease agreements, undrawn letters of credit and derivative contracts. 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. See Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements.

	Payments Due by Period				
	Total	2008	2009 and 2010	2011 and 2012	2013 and Beyond
			(in thousands)		
Long-term debt (excludes interest) (1)	$ 1,880,000	$ 25,000	$ 25,000	$ 1,180,000	$ 650,000
Drilling and equipment obligations (2) :					
United States drilling and equipment	462,759	181,337	173,935	107,487	-
International drilling and equipment	68,170	68,170	-	-	-
Purchase obligations (3)	194,419	194,419	-	-	-
Throughput agreement (4)	95,000	-	38,000	38,000	19,000
Operating lease obligations (5) :					
Office buildings and facilities	52,894	7,289	14,495	13,247	17,863
Oil and gas operations equipment	12,074	5,467	6,607	-	-
Other long-term liabilities (6) :					
Asset retirement obligations (7)	144,288	13,332	12,443	13,034	105,479
Derivative instruments (8)	603,133	525,159	77,974	-	-
Total contractual obligations	$ 3,512,737	$ 1,020,173	$ 348,454	$ 1,351,768	$ 792,342

(1) Based on the total debt balance outstanding at December 31, 2007, scheduled maturities and interest rates in effect at December 31, 2007, our cash payments for interest would be $109 million in 2008, $108 million in 2009, $107 million in 2010, $107 million in 2011, $107 million in 2012 and $990 million for the remaining years for a total of $1.5 billion. See Item 8. Financial Statements and Supplementary Data—Note 7—Debt for additional information regarding our long-term debt obligations.

(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 facilities. See Item 8. Financial Statements and Supplementary Data—Note 14—Commitments and Contingencies for additional information regarding our drilling and equipment obligations.

(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 14—Commitments and Contingencies for additional information regarding our purchase obligations.

(4) In January 2007, we entered into a five-year throughput agreement. The transporting pipeline is expected to be completed and operational in 2009. See Item 8. Financial Statements and Supplementary Data—Note 14—Commitments and Contingencies for additional information regarding our throughput agreement.

(5) 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 14—Commitments and Contingencies for additional information regarding our operating lease obligations.

(6) The table does not include our deferred compensation liabilities of $225 million and our accrued benefit costs of $51 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans for additional information on our deferred compensation liability and our accrued benefit costs.

(7)

Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data—Note 6—Asset Retirement Obligations for additional information on our asset retirement obligations.

(8) See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities for additional information on our derivative instrument obligations.

We accrued approximately $12 million as of December 31, 2007, 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 $1 million at December 31, 2007.

Other

Contributions to Pension and Other Postretirement Benefit Plans—We made contributions to the pension, restoration and other postretirement benefit plans totaling $12 million during 2007, $36 million during 2006, and $14 million during 2005. The actual return on plan assets was $13 million in both 2007 and 2006. 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 pension plans become fully funded over a seven-year period beginning in 2008. As a result of previous contributions made to the pension plan, there are no required contributions expected during 2008. We may, however, make additional contributions to our pension plan. We expect to make contributions of $4 million to the unfunded restoration and medical and life plans in 2008. This amount is equal to the benefits expected to be paid by those plans.

Income Taxes—We made cash payments for income taxes, net of refunds, of $149 million during 2007, $115 million during 2006 and $122 million during 2005.

Contingencies—During 2007, we paid a total of $56 million to settle legal proceedings; these amounts had been accrued previously. During 2006 and 2005, 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.

RESULTS OF OPERATIONS

Net Income

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:

- a $332 million, or 11%, increase in total revenues, due primarily to higher average realized crude oil prices and higher average realized US natural gas prices and an increase in income from equity method investees;
- a $395 million decrease in loss on derivative instruments; and

offset by:

- a $208 million decrease in gains from asset sales;
- a $105 million increase in DD&A expense;
- a $51 million loss on involuntary conversion expense; and
- a $51 million increase in oil and gas exploration expense.

Net income for 2006 was $678 million, a 5% increase over 2005. Factors contributing to the increase in net income from 2005 to 2006 included:

- a $753 million, or 34%, increase in total revenues, driven primarily by a full year of Patina operations and nine months of U.S. Exploration operations and higher average realized oil prices;
- an increase of $215 million in gains from asset sales;

offset by:

- an increase in loss on derivative instruments of $360 million; and
- a $232 million increase in DD&A expense.

Natural Gas Information

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Natural gas sales	$ 1,271,866	$ 1,211,782	$ 1,023,644

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

	Year Ended December 31,					
	2007		2006		2005	
	Mcfpd	$/Mcf	Mcfpd	$/Mcf	Mcfpd	$/Mcf
United States (1)	412,212	$ 7.51	451,712	$ 6.61	343,953	$ 7.43
West Africa (2)	132,464	0.29	45,422	0.37	65,581	0.25
North Sea	6,235	6.54	8,130	8.00	9,299	5.93
Israel	110,820	2.79	92,894	2.72	66,377	2.68
Ecuador (3)	25,713	-	24,475	-	22,795	-
Other International	-	-	294	0.96	190	1.10
Total	687,444	$ 5.26	622,927	$ 5.55	508,195	$ 5.78

(1) Reflects an increase of $1.12 per Mcf in 2007 and reductions of $0.25 per Mcf in 2006 and $0.77 per Mcf in 2005 from hedging activities.
(2) 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 facility. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes sold by the LPG plant are included in the table below under crude oil information. Natural gas volumes include sales to an LNG facility of 78,090 Mcfpd 2007; there were no natural gas sales to the LNG facility before 2007. The natural gas sold to the LNG facility and methanol plant has a lower Btu content than the natural gas sold to the LPG plant. As a result of the natural gas volumes sold to the LNG plant in 2007, the average price received on an Mcf basis is lower. For 2007 and 2006, the price on an Mcf basis has been adjusted to reflect the Btu content on gas sales.
(3) The natural gas-to-power project in Ecuador is 100% owned by one of our subsidiaries, and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales included in total revenues totaled $71 million in 2007, $72 million in 2006 and $74 million in 2005.

2007 Compared with 2006—Natural gas sales increased a net $60 million, or 5%, during 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 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 Israeli Electric Company's Reading power plant in Tel Aviv, as well as the start up of sales to a desalinization plant and a paper mill.

2006 Compared with 2005—Natural gas sales increased a net $188 million, or 18%, during 2006 as compared with 2005. Again, the change was caused by both significant volume and price changes. In the US natural gas sales increased by $157 million from the previous year due to additional US production from Patina properties acquired in 2005 and from U.S. Exploration properties acquired in May 2006. In addition, there were increases in deepwater Gulf of Mexico production where three new developments came on stream at Swordfish, Ticonderoga and Lorien. However, increases due to higher gas sales volumes were partially offset by lower average realized prices.

Internationally, West Africa natural gas sales were flat year-to-year; however, there was a decline in sales volumes due to the turnaround of the AMPCO methanol plant in Equatorial Guinea. The turnaround lasted 57 days and was followed by reduced production levels caused by 35 days of compressor repairs. The production decline was completely offset by an increase in average realized natural gas prices. In the North Sea, natural field decline resulted in reduced sales volumes, but this reduction was more than offset by the increase in average realized prices. Israel experienced a $4 million increase in natural gas sales primarily due to increased demand from Israel Electric Corporation Limited, a full year of sales to Bazan Oil Refinery and commencement of natural gas sales to the Reading power plant in Tel Aviv, Israel.

Natural Gas Hedging Activities—Natural gas sales are net of the effects of derivative contracts that are accounted for as cash flow hedges and included an increase of $169 million in 2007, and a reduction of $42 million in 2006 and $97 million in 2005 from hedging activities. Natural gas sales in 2007 include a $182 million non-cash increase related to hedge contracts that were redesignated at the time of the Gulf of Mexico shelf property sale in 2006 and settled during 2007. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Crude Oil Information

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Crude oil sales	$ 1,694,233	$ 1,489,459	$ 942,778

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

	Year Ended December 31,							
	2007			2006			2005	
	Production(1)	Sales		Production (1)	Sales		Sales (2)	
	Bopd	Bopd	$/Bbl	Bopd	Bopd	$/Bbl	Bopd	$/Bbl
United States (3)	42,332	42,332	$ 53.22	45,798	45,798	$ 50.68	25,941	$ 46.67
West Africa (4)	15,523	15,070	71.27	17,326	17,860	62.51	17,786	42.51
North Sea	12,813	12,505	76.47	3,988	3,717	67.43	5,380	52.68
Other International (5)	6,806	6,674	53.69	7,491	7,540	52.05	7,851	42.37
Total Consolidated Operations	77,474	76,581	60.61	74,603	74,915	54.47	56,958	45.35
Equity Investees (6)	8,014	7,684	55.09	7,531	8,032	45.83	3,240	43.43
Total	85,488	84,265	$ 60.10	82,134	82,947	$ 53.64	60,198	$ 45.25

(1) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.

(2) Sales volumes equal production volumes in 2005.

(3) Reflects reductions of $13.68 per Bbl in 2007, $11.41 per Bbl in 2006 and $8.03 per Bbl in 2005 from hedging activities.

(4) Reflects reductions of $2.19 per Bbl in 2007 and $9.93 per Bbl in 2005 from hedging activities. We did not hedge West Africa crude oil sales in 2006.

(5) Other international includes China and Argentina.

(6) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG sales volumes totaled 5,848 Bopd in 2007, 6,294 Bopd in 2006 and 2,328 Bopd in 2005.

2007 Compared with 2006—Crude oil sales increased a net $205 million, or 14%, during 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 shut-in. 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 Gulf of Mexico shelf properties in 2006. Northern region production was negatively impacted by severe winter weather in the Rocky Mountains during 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, and the overall US volume decline was partially offset by higher average realized prices.

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.

2006 Compared with 2005—Crude oil sales increased a net $547 million, or 58%, during 2006 as compared with 2005. Again, the increase was caused by significant volume and price changes. In the US crude oil sales increased by $405 million from the previous year due to additional US production from Patina properties acquired in 2005 and from U.S. Exploration properties acquired in May 2006. In addition, there were increases in deepwater Gulf of Mexico production where three new developments came on stream at Swordfish, Ticonderoga and Lorien.

Internationally, higher average realized prices resulted in an increase of $132 million in West Africa crude oil sales and contributed to most of the $22 million increase in other international crude oil sales. The North Sea experienced a $12 million decrease in crude oil sales. Natural field decline and timing of tanker liftings resulted in lower sales volumes, the effect of which was mitigated by an increase in average realized crude oil prices.

Crude Oil Hedging Activities—Crude oil sales are net of the effects of derivative contracts that are accounted for as cash flow hedges and included a reduction of $223 million in 2007, $191 million in 2006 and $140 million in 2005 from hedging activities. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Commodity 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 product price fluctuations. Such instruments include variable to fixed price swaps, costless collars and basis swaps. Although these derivative instruments expose us to credit risk, we monitor the creditworthiness of counterparties and believe that losses from nonperformance are unlikely to occur. Hedging gains and losses related to crude oil and natural gas production are recorded in oil and gas sales. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk and Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Income from Equity Method Investees

We own a 45% interest in AMPCO, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant, which owns and operates an LPG processing plant. 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,		
	2007	2006	2005
Net income (in thousands):			
AMPCO and affiliates	$ 82,877	$ 38,024	$ 56,896
Alba Plant	128,051	101,338	33,916
Distributions/dividends (in thousands):			
AMPCO and affiliates	96,483	37,350	59,625
Alba Plant	132,251	155,158	-
Sales volumes (1):			
Methanol (Kgal)	160,540	109,942	162,446
Condensate (Bopd)	1,836	1,738	912
LPG (Bpd)	5,848	6,294	2,328
Production volumes (1):			
Condensate (Bopd)	1,860	1,730	912
LPG (Bpd)	6,154	5,801	2,328
Average realized prices:			
Methanol (per gallon)	$ 1.09	$ 0.90	$ 0.77
Condensate (per Bbl)	74.87	66.60	55.76
LPG (per Bbl)	48.87	40.10	38.63

(1) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.

Net income from AMPCO and affiliates increased substantially in 2007 relative to 2006 due to a 46% increase in methanol sales volumes and a 21% increase in 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.

Net income from AMPCO and affiliates decreased 33% in 2006 relative to 2005 due to a 32% decrease in methanol sales volumes offset by a 17% increase in average realized methanol prices. The decrease in methanol sales volumes was due to the 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006 followed by 35 days of compressor repairs. No such shutdown or plant turnaround occurred during 2005.

Net income from Alba Plant increased 26% in 2007 relative to 2006 due to a 22% increase in average realized LPG prices and a 12% increase in average realized condensate prices.

Net income from Alba Plant increased substantially in 2006 relative to 2005 due to an almost threefold increase in LPG sales volumes, an almost twofold increase in condensate sales volumes and a 19% increase in average realized condensate prices. The increases in LPG and condensate sales volumes reflected the completion and ramp up to full production of the Phase 2B liquids expansion project.

For 2007, $132 million received from Alba Plant was classified within operating cash flows as a dividend from equity method investee as compared with 2006 in which the distributions 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.

Costs and Expenses

Production Costs—Production costs were as follows:

	Total	United States	West Africa	North Sea	Israel	Other Int'l/ Corporate (2)
			(in thousands)			
Year Ended December 31, 2007						
Oil and gas operating costs (1)	$ 299,622	$ 190,723	$ 39,222	$ 37,987	$ 7,712	$ 23,978
Workover and repair expense	22,830	22,516	-	-	-	314
Lease operating expense	322,452	213,239	39,222	37,987	7,712	24,292
Production and ad valorem taxes	113,547	91,225	-	-	-	22,322
Transportation expense	51,699	39,542	-	10,523	-	1,634
Total production costs	$ 487,698	$ 344,006	$ 39,222	$ 48,510	$ 7,712	$ 48,248
Year Ended December 31, 2006						
Oil and gas operating costs (1)	$ 270,136	$ 205,348	$ 26,557	$ 11,655	$ 9,066	$ 17,510
Workover and repair expense	46,951	46,793	-	-	-	158
Lease operating expense	317,087	252,141	26,557	11,655	9,066	17,668
Production and ad valorem taxes	108,979	85,960	-	-	-	23,019
Transportation expense	28,542	20,728	-	7,010	-	804
Total production costs	$ 454,608	$ 358,829	$ 26,557	$ 18,665	$ 9,066	$ 41,491
Year Ended December 31, 2005						
Oil and gas operating costs (1)	$ 203,833	$ 136,087	$ 30,661	$ 12,244	$ 8,504	$ 16,337
Workover and repair expense	14,027	13,734	-	259	-	34
Lease operating expense	217,860	149,821	30,661	12,503	8,504	16,371
Production and ad valorem taxes	78,703	65,428	-	-	-	13,275
Transportation expense	16,764	9,350	-	6,562	-	852
Total production costs	$ 313,327	$ 224,599	$ 30,661	$ 19,065	$ 8,504	$ 30,498

(1) Oil and gas operating costs include labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs.

(2) Other international includes Ecuador, China and Argentina.

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

Oil and gas operating costs increased $66 million, or 33%, from 2005 to 2006 primarily as a result of our expanded operations. Three new deepwater Gulf of Mexico development projects came online between December 2005 and April 2006. Fiscal year 2006 represented a full year of Patina operations, and we acquired U.S. Exploration in 2006. In addition, the high commodity price environment resulted in higher service, contract labor and fuel costs. Insurance costs were also higher in 2006 due in part to increased rates for property damage coverage combined with the added costs of providing business interruption coverage on deepwater Gulf of Mexico assets.

Workover and repair expense decreased $24 million during 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.

Workover and repair expense increased $33 million during 2006 as compared with 2005. Expense for 2006 included $30 million ($0.45 per BOE) of hurricane-related repair expense.

Production and ad valorem tax expense increased $5 million, or 4%, during 2007 as compared with 2006 and increased $30 million, or 38%, during 2006 as compared with 2005. The increase reflects additional production from U.S. Exploration and Patina properties. These properties have proportionately more production subject to such taxes.

Transportation expense increased $23 million, or 81%, during 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. Transportation expense increased $12 million, or 70%, during 2006 as compared with 2005. The increase was primarily due to a full year of Patina operations and U.S. Exploration.

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

	Year Ended December 31,		
	2007	2006	2005
Oil and gas operating costs	$ 4.29	$ 4.14	$ 3.94
Workover and repair expense	0.33	0.72	0.27
Lease operating costs	4.62	4.86	4.21
Production and ad valorem taxes	1.63	1.67	1.52
Transportation expense	0.74	0.44	0.33
Total production costs (1) (2)	$ 6.99	$ 6.97	$ 6.06

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

(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.51 per BOE for 2007.

The unit rates of total production costs per BOE, converting gas to oil on the basis of six Mcf per barrel, have been increasing year-over-year since 2005. The increases are due to rising third-party costs, including insurance, hurricane-related repair expense, and higher production taxes.

Oil and Gas Exploration Expense—Exploration expense was as follows:

	Total	United States	West Africa	North Sea	Israel	Other Int'l/ Corporate (1)
			(in thousands)			
Year Ended December 31, 2007						
Dry hole expense	$ 90,210	49,473	$ 40,399	$ 5	$ -	$ 333
Unproved lease amortization	16,013	15,176	-	103	-	734
Seismic	64,856	55,258	939	8,184	691	(216)
Staff expense	45,030	11,900	2,106	8,318	645	22,061
Other	2,973	2,423	100	340	82	28
Total exploration expense	$ 219,082	$ 134,230	$ 43,544	$ 16,950	$ 1,418	$ 22,940
Year Ended December 31, 2006						
Dry hole expense	$ 70,325	$ 66,150	$ 46	$ 4,129	$ -	$ -
Unproved lease amortization	18,836	18,823	-	13	-	-
Seismic	37,676	29,320	4,204	685	3	3,464
Staff expense	38,861	12,710	2,887	4,816	250	18,198
Other	2,226	1,083	192	879	33	39
Total exploration expense	$ 167,924	$ 128,086	$ 7,329	$ 10,522	$ 286	$ 21,701
Year Ended December 31, 2005						
Dry hole expense	$ 98,015	$ 95,678	$ 1,403	$ 932	$ 2	$ -
Unproved lease amortization	17,855	17,855	-	-	-	-
Seismic	21,761	11,631	316	1,544	-	8,270
Staff expense	34,945	16,255	3,760	2,690	189	12,051
Other	5,850	4,974	(16)	819	32	41
Total exploration expense	$ 178,426	$ 146,393	$ 5,463	$ 5,985	$ 223	$ 20,362

(1) Other international includes Ecuador, China, Argentina and Suriname.

Exploration expense increased $51 million, or 30% during 2007 as compared with 2006. US dry hole expense decreased $17 million due to a reduction in the number of dry holes drilled during 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 in which commercial hydrocarbons were not found. Seismic expense increased a net $27 million during 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 $6 million primarily due to new venture activity.

Exploration expense decreased $11 million, or 6% during 2006 as compared with 2005. US dry hole expense was $30 million less due to the reduction in the number of dry holes drilled. US seismic expense increased $18 million due primarily to the expansion of our deepwater Gulf of Mexico 3D seismic database. In addition, other international staff expense increased $6 million due to new venture activity.

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

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
United States	$ 574,001	$ 543,431	$ 311,153
West Africa	25,315	23,620	27,121
North Sea	79,450	8,123	9,888
Israel	17,842	13,947	11,188
Other international, corporate, and other	31,373	33,487	31,194
Total DD&A expense	$ 727,981	$ 622,608	$ 390,544
Unit rate of DD&A per BOE (1) (2)	$ 10.43	$ 9.54	$ 7.55

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

(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.62 per BOE for 2007.

Total DD&A expense has been increasing since 2005 primarily due to higher production volumes. The increase in the unit rate for 2007 as compared with 2006 was primarily due to higher acquisition and development costs in the the US and the Dumbarton North Sea development. The increase in the unit rate for 2006 as compared with 2005 was primarily due to the change in the mix of our production volumes, in particular, deepwater Gulf of Mexico production.

DD&A expense includes abandoned assets cost of $5 million in 2007, $1 million in 2006 and $11 million in 2005.

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

	Year Ended December 31,		
	2007	2006	2005
General and administrative expense (in thousands)	$ 206,378	$ 164,541	$ 100,125
Unit rate per BOE (1) (2)	$ 2.96	$ 2.52	$ 1.94

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

(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.21 per BOE for 2007.

G&A expense increased $42 million, or 25%, during 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 effects of adoption of SFAS No. 123(R), “Share-Based Payment” (“SFAS 123(R)”), combined with additional equity-based awards, resulted in a $14 million increase in stock-based compensation expense included in G&A during 2007. Stock-based compensation expense included in G&A totaled $25 million in 2007.

G&A expense increased $64 million, or 64% during 2006 as compared with 2005. The increase was due to higher salaries and wages and the inclusion of a full year of G&A expense related to Patina operations. Salaries and wages also reflected wage inflation due to a tight labor market and expanded activity across the industry driven by higher commodity prices. In addition, the effects of adoption of SFAS 123(R), combined with additional equity-based awards, resulted in a $7 million increase in stock-based compensation expense included in G&A during 2006. Stock-based compensation expense included in G&A was $11 million in 2006 as compared with $4 million in 2005.

G&A includes actuarially-computed net periodic benefit cost related to pension and other postretirement benefit plans of $17 million in 2007, $19 million in 2006 and $11 million in 2005.

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

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Interest expense, net	$ 112,957	$ 117,045	$ 87,541
Capitalized interest	16,595	12,515	8,684

Interest expense, net of capitalized interest, decreased in 2007 primarily due to a declining rate of interest applicable to the Credit Facility from 5.69% at December 31, 2006 to 5.28% at December 31, 2007. Interest expense, net of capitalized interest, increased in 2006 due to additional borrowings related to the Patina Merger and acquisition of U.S. Exploration and to increases in the interest rate applicable to the Credit Facility from 4.82% at December 31, 2005 to 5.69% at December 31, 2006.

Interest is capitalized on 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 related to long lead-time projects in West Africa, the North Sea and deepwater Gulf of Mexico in 2007; the North Sea and deepwater Gulf of Mexico in 2006; and deepwater Gulf of Mexico and projects in West Africa in 2005.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. At December 31, 2007, AOCL included a deferred loss of $4 million, net of tax, related to interest rate swaps. $3 million of 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. The remaining $1 million loss relates to interest rate locks that will expire in third quarter 2008. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

(Gain) Loss on Derivative Instruments—See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Gain on Sale of Assets—See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

Loss on Involuntary Conversion—See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

Electricity Sales—Ecuador Integrated Power Project—Through our subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., 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 expense, net in the consolidated statements of operations.

Operating data is as follows:

	Year Ended December 31,		
	2007	2006	2005
Electricity sales (in thousands)	$ 70,916	$ 71,603	$ 74,228
Electricity generation expense (in thousands)	56,552	59,494	53,137
Operating income (in thousands)	14,364	12,109	21,091

Power generation (MW)		911,830		865,983		799,160
Average power price ($/Kwh)	$	0.078	$	0.083	$	0.093

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.

43

Electricity generation expense includes net increases in the allowance for doubtful accounts of $14 million in 2007, $15 million in 2006 and $11 million in 2005. These increases have been made to cover potentially uncollectible balances related to the Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation.

Gathering, Marketing and Processing—We market a portion of our US natural gas production, as well as certain third-party natural gas. We sell natural gas directly to end-users, natural gas marketers, industrial users, interstate and intrastate pipelines, power generators and local distribution companies. We also market certain third-party crude oil. Gathering, marketing and processing (“GMP”) proceeds are included in other revenues and GMP expenses are included in other expense, net in the consolidated statements of operations. Gross margin from GMP activities was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
GMP proceeds	$ 24,087	$ 27,876	$ 55,261
GMP expenses	17,539	18,664	28,067
Gross margin	$ 6,548	$ 9,212	$ 27,194

We employ derivative instruments in connection with purchases and sales of third-party production to lock in profits or limit exposure to commodity price risk. Most of the purchases we make are on an index basis. However, purchasers in the markets in which we sell often require fixed or NYMEX-related pricing. We record gains and losses on these derivative instruments using mark-to-market accounting. Gains (losses) were de minimis for 2007, 2006 and 2005. GMP proceeds for 2005 includes a gain of $11 million for the sale of certain gas sales and transportation contractual assets.

Deferred Compensation Expense—In connection with the Patina Merger, 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, 2007, 45% of the market value of the assets in the rabbi trust related to our common stock. Deferred compensation expense totaled $34 million, $16 million and $15 million for 2007, 2006, and 2005, respectively. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans.

Impairment of Operating Assets—We recorded impairments of $4 million in 2007, $9 million in 2006 and $5 million in 2005, 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. Impairment expense is included in other expense, net in the consolidated statements of operations.

Income Taxes—The income tax provision was as follows:

	Year Ended December 31,		
	2007	2006	2005
Income tax provision (in thousands)	$ 423,697	$ 417,789	$ 322,940
Effective rate	31.0%	38.1%	33.3%

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 the 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.

Our effective tax rate increased significantly in 2006 from 2005 due to several factors. The most significant factor was the nondeductible goodwill write-off of $100 million related to the sale of the Gulf of Mexico shelf properties discussed in the preceding paragraph. The rate was also 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. 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.

The 2005 effective tax rate was impacted by our ability to claim a foreign tax credit for the income taxes paid by foreign branch operations, as well as a benefit realized on the repatriation of foreign earnings under the American Jobs Creation Act of 2004.

PART IV

Item 15. Exhibits, Financial Statements Schedules.

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

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

SIGNATURES

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

	NOBLE ENERGY, INC. (Registrant)
Date: May 19, 2008	By: /s/ Chris Tong Chris Tong, Senior Vice President, Chief Financial Officer

INDEX TO EXHIBITS

The Index to Exhibits on pages 106 through 108 of the Annual Report on Form 10-K for the fiscal year ended December 31, 2007 is amended by the addition of the following exhibits:

Exhibit Number		Exhibit
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
23.5	—	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
31.3	—	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).
31.4	—	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).
32.3	—	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).
32.4	—	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).