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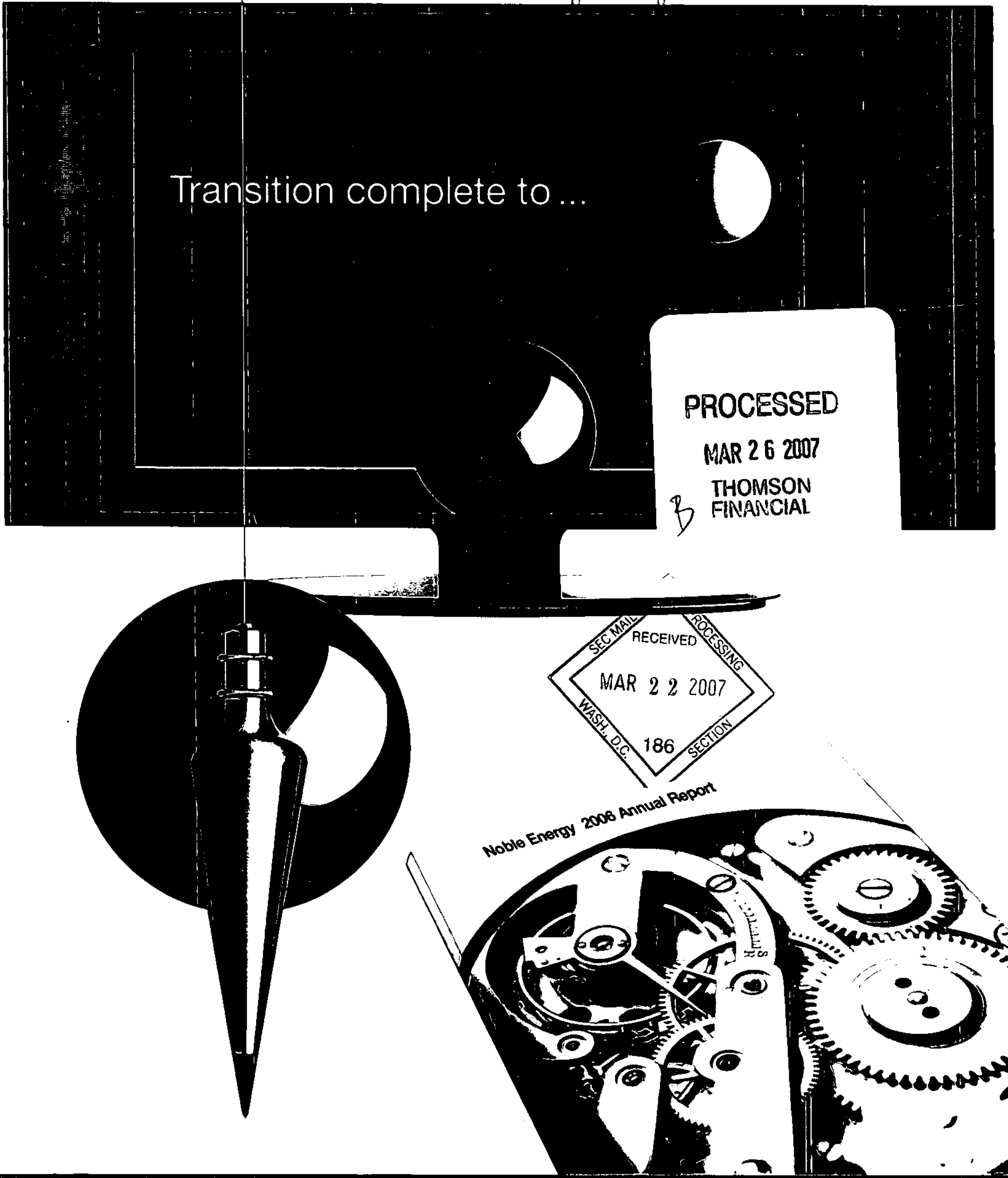
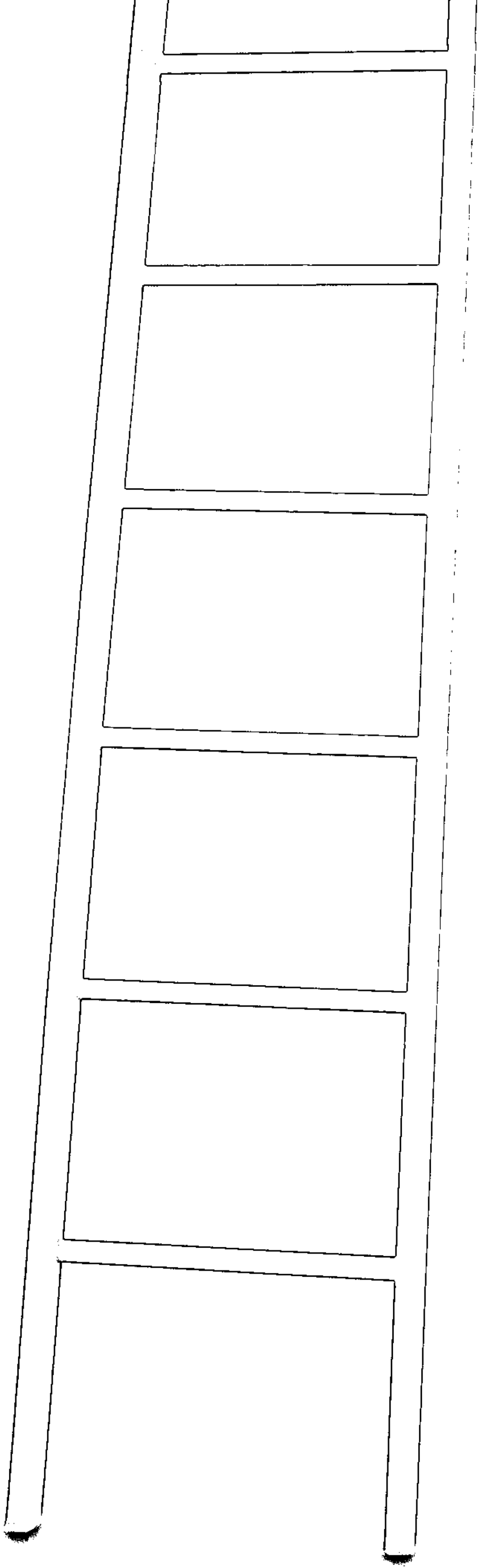


...a balanced company with a simplified business model.

In 2006, we completed our transition to a simplified business model based on building a portfolio of high quality and long-lived assets with an inventory of lower risk development projects and an exploration program offering substantial long-term impact. Over the past four years, we have undertaken a number of steps that have led to the realization of the business model envisioned in 2003:

- Several major international projects have been completed on time and within budget.
- A large portfolio of lower risk, long-lived assets has been added.
- The exploration portfolio has been strengthened.
- Mature and declining assets have been sold.
- Our global asset base is now balanced between International and North America.

Going forward, we will pursue a broad array of projects, from lower risk development to high-growth exploration.



2006

- Ticonderoga and Lorien commenced production in the deepwater Gulf of Mexico
- Signed Niobrara joint venture agreement with Teton Energy Corporation
- Sold Gulf of Mexico shelf assets
- Commenced common stock repurchase program totaling $500 million
- Raton and Redrock discoveries in the deepwater Gulf of Mexico
- Agreed to acquire U.S. Exploration Holdings, Inc. with assets in the DJ basin
- Acquired 50 percent working interest in the PH-77 license offshore Cameroon
- Increased natural gas sales in Israel

2005

- Phase 2B liquids expansion project in Equatorial Guinea completed and production commenced
- Swordfish commenced production in the deepwater Gulf of Mexico
- Belinda discovery on Block 'O' offshore Equatorial Guinea
- Acquired 30 percent working interest in exploration block offshore Suriname
- Sanctioned Dumbarton field development in the North Sea

2004

- Commenced natural gas sales in Israel
- Announced merger with Patina Oil & Gas Corporation, enhancing U.S. asset portfolio
- Ticonderoga discovery and acquisition of additional ownership in Swordfish and Lorien in the deepwater Gulf of Mexico
- Signed production contract for Block 'O' and farmed into Block 'I' offshore Equatorial Guinea

2003

- Commenced production from the Cheng Dao Xi field in South Bohai Bay offshore China
- First full year of operations at the Machala power plant in Ecuador
- Phase 2A condensate expansion project in Equatorial Guinea completed and operations commenced

Transition complete

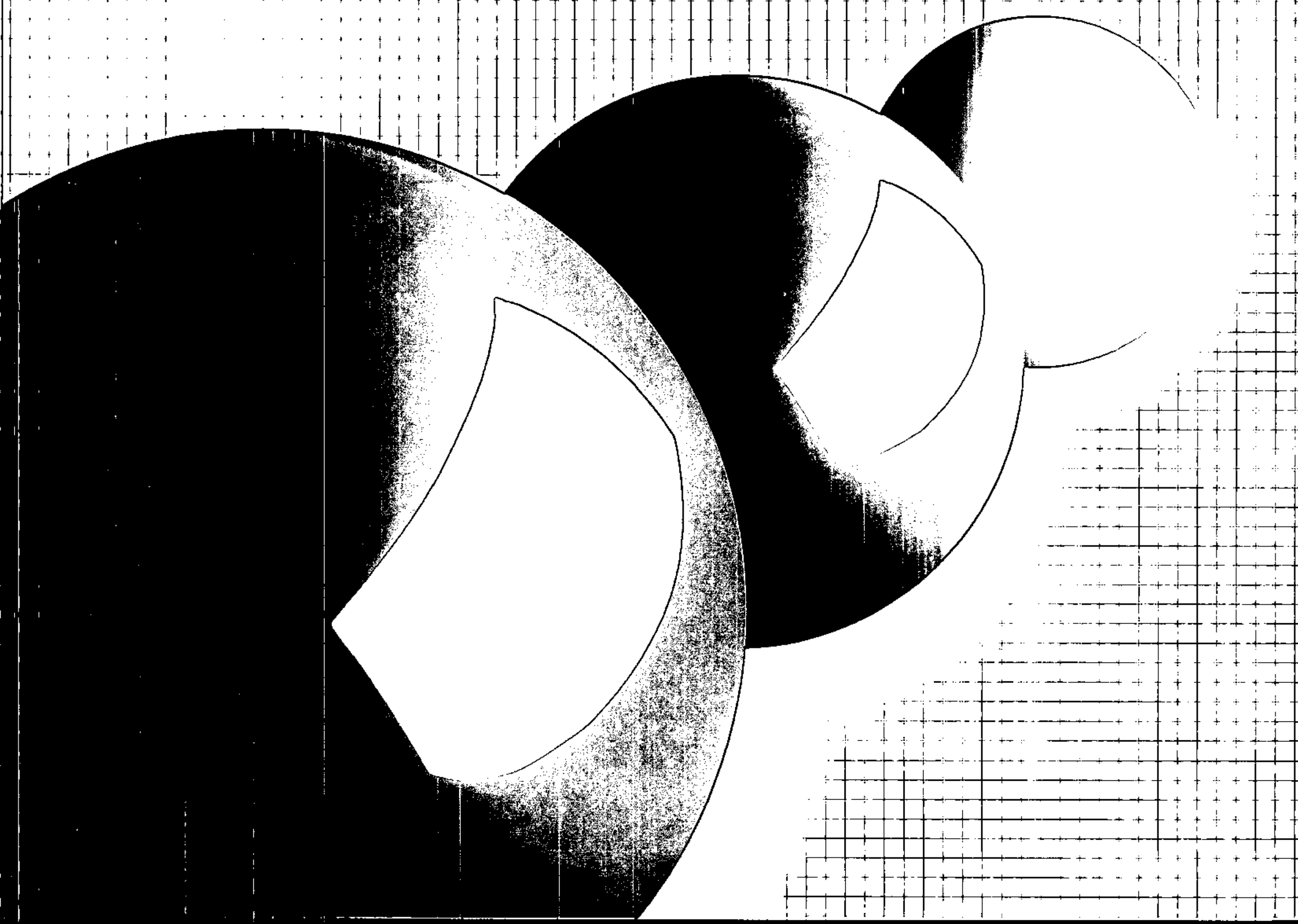
As 2006 came to a close, a new business model had been successfully implemented, creating a new company with a significantly stronger asset portfolio containing thousands of lower risk development projects, a global exploration portfolio providing substantial upside and a reserve base balanced equally between North America and International. But much remains to be done...

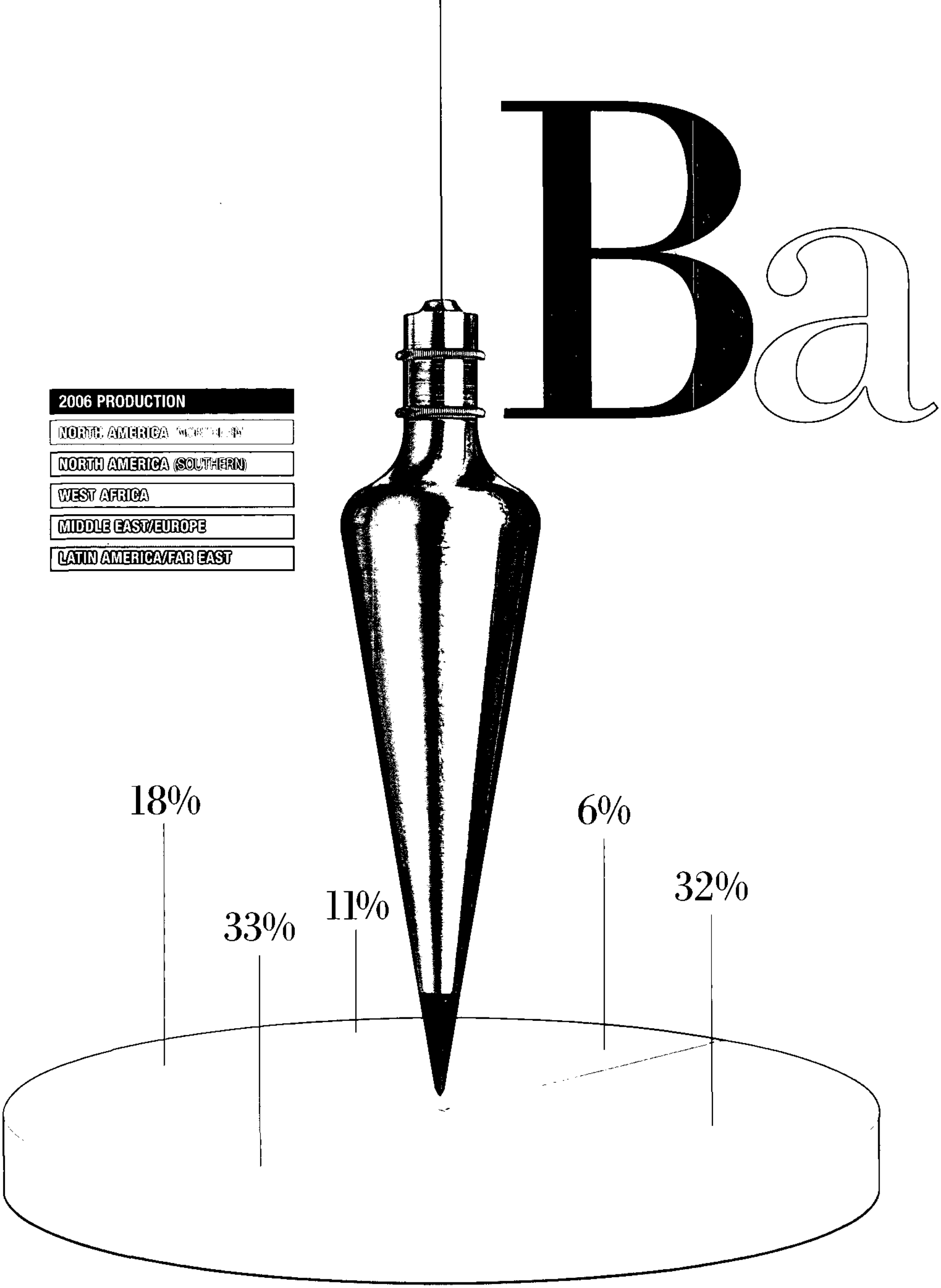
MORE WORK AHEAD

We simplified

OUR BUSINESS MODEL

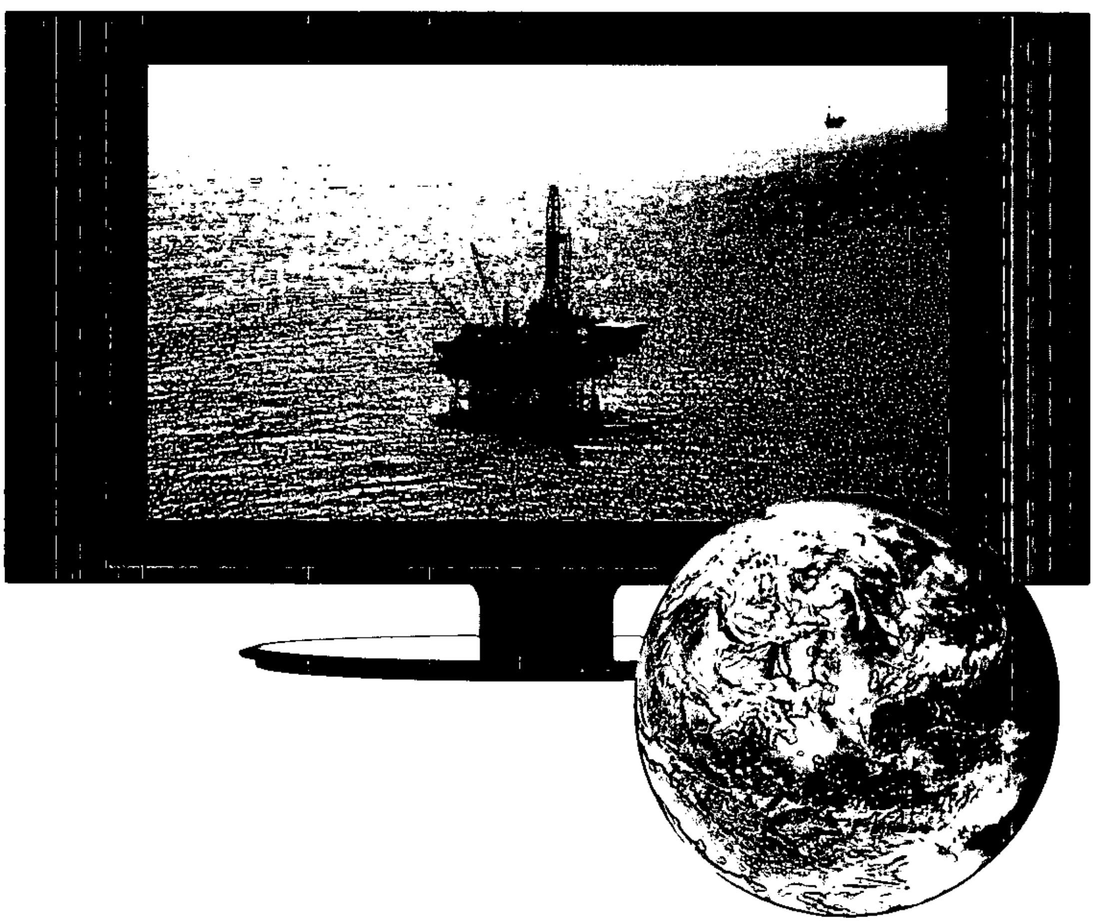
FOUNDATION Our simplified business model is built on a portfolio of high quality, long-lived assets. Our largest asset in North America, the Wattenberg field, offers a stable base of long-lived production. Internationally, completed projects in Equatorial Guinea, Israel, China, Ecuador and Argentina will provide low-cost, high rate of return production for years to come. **NEAR-TERM GROWTH** We have a large inventory of high return and lower risk projects offering significant near-term growth. Assets located primarily in the Rocky Mountain and Mid-continent areas of North America, such as the Wattenberg field, Niobrara, the Piceance basin, Buffalo Wallow and Billy Rose, will provide growth for several years. **LONG-TERM GROWTH** With a broad-based, global exploration portfolio in regions including the deepwater Gulf of Mexico, West Africa, the Middle East and South America, we have exposure to substantial net, risked resource potential that could create a new phase of growth.




Ba
2006 PRODUCTION
NORTH AMERICA (NORTHERN)
NORTH AMERICA (SOUTHERN)
WEST AFRICA
MIDDLE EAST/EUROPE
LATIN AMERICA/FAR EAST
18%
33%
11%
6%
32%

In 2003, we relied on short-lived, high decline rate assets for over half of our production. Since then, we have successfully transitioned to a balanced and diversified mix of assets, as reflected in our 2006 production profile.

lance



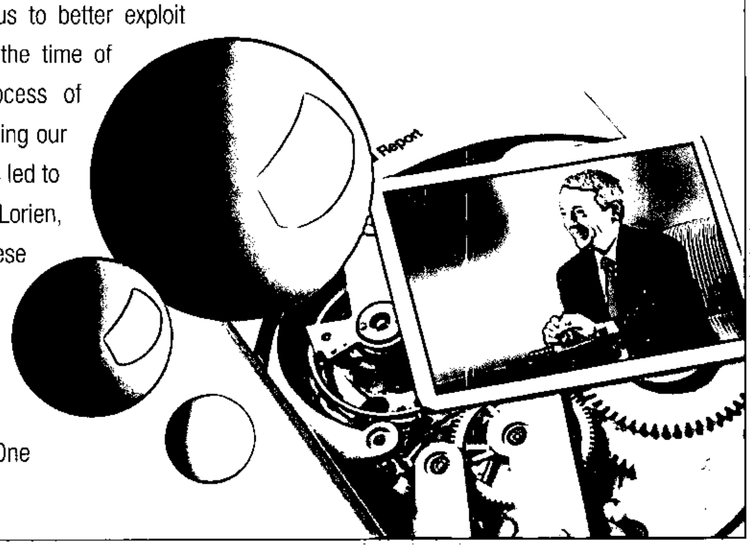
LETTER TO SHAREHOLDERS

2006 was an outstanding year for Noble Energy in terms of both financial and operational results. Our earnings per share was $3.79, and our discretionary cash flow of $2.1 billion was a record for the company. Our strong cash flow and project inventory allowed us to carry out a capital investment program of over $1.8 billion, including acquisitions, while also initiating a $500 million share repurchase program. For the year, our production grew 28 percent to a record of 185,954 barrels oil equivalent per day (Boepd). The results of our investment program allowed us to add new reserves totaling 179 percent of our annual production. At year-end, our reserves totaled a record 835 million barrels oil equivalent (MMBoe). During the year, we significantly enhanced our asset portfolio by divesting of our legacy shallow water Gulf of Mexico assets, adding to our Rocky Mountain portfolio through the acquisition of U.S. Exploration Holdings, Inc. (USX), and expanding our deepwater Gulf of Mexico position. Our unit costs continued to improve resulting in a cost structure that was in the best quartile relative to our peers. Most importantly, our share price grew 22 percent, which led to our total shareholder return being the best in our peer group for the year.

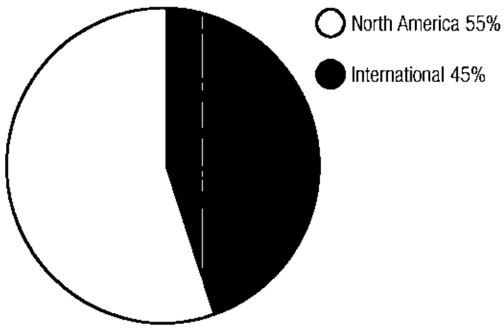
Our excellent performance in 2006 can be traced back, in part, to a new business model, which we developed and began implementing in 2003. The foundation of this model was to build a portfolio of high quality and long-lived assets that possessed an inventory of lower-risk development projects. By increasing our investment in these types of projects, we lowered the risk and gained predictability in our near-term production growth. This new model also anticipated a transition of our exploration program towards the pursuit of prospects that had long-term impact for the company.

When we adopted this model, our international business was rapidly growing with the development of several high-quality projects. These included our development of a major gas field offshore Israel, a gas-to-power project in Ecuador, the development of a new oil field in the Bohai Bay of China and two phases of expansion of our major property in Equatorial Guinea. With these important projects, our international business has transitioned from a large consumer of cash flow to one that generates substantial free cash. Also at that time, our North American portfolio was still concentrated in the Gulf Coast, both onshore and offshore, which were areas dominated by high decline rate assets. We recognized that future investment opportunities in these areas, in particular in the Gulf of Mexico shelf, were limited, and we needed to enhance our North American portfolio with longer-lived assets that contained an inventory of development projects.

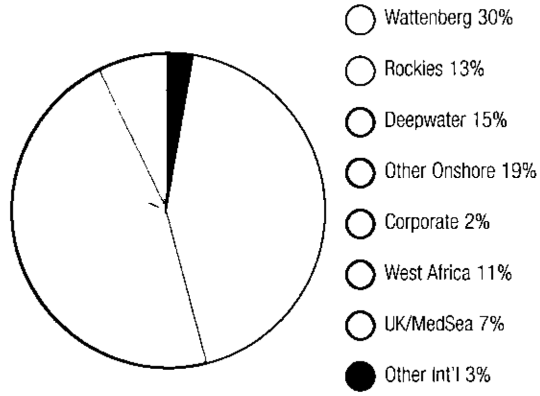
The 2005 merger with Patina Oil & Gas Corporation (Patina) brought us the assets and project inventory that we were seeking. With the completion of this merger in mid-2005, we had access to an almost ten-year inventory of high-return development projects in the Mid-continent and Rocky Mountain regions. In addition, Patina's expertise in developing unconventional natural gas resources allowed us to better exploit some of our legacy assets in the Rockies. At the time of the merger, we had already begun the process of strengthening our exploration portfolio by increasing our investments in the deepwater Gulf of Mexico. This led to several deepwater discoveries including the Lorien, Swordfish and Ticonderoga fields. All three of these new fields began delivering production starting in late 2005 through early 2006, and were significant contributors to our production growth this past year. We also began enhancing our international portfolio of exploration prospects. One



2006 GLOBAL RESERVES



2007 CAPITAL PROGRAM



of the most notable areas where we expanded was in West Africa, where we obtained positions in two blocks in Equatorial Guinea. It was on one of these blocks, Block 'O,' that we made our Belinda discovery in late 2005. During 2006, we added to our West Africa position by securing additional acreage offshore nearby Cameroon.

At the close of 2006, we find that our portfolio of assets has been significantly strengthened from what it was just a few years ago. Our proved reserves are more evenly balanced between domestic and international assets as are our unproven resources. We now have a higher quality portfolio of lower-risk development projects, primarily in the Mid-continent and Rocky Mountain areas of the U.S. Our deepwater exploration portfolio has been expanded, where we added two additional discoveries in 2006 at Redrock and Raton. We have balanced our growth between North America and International with both areas providing near-term growth as well as long-term opportunities.

NORTH AMERICA OVERVIEW

Our North America operations once again showed substantial growth in 2006. Production was over 121,000 Boepd, up 45 percent from 2005, reflecting a full year's impact from the Patina assets and the impact of several new deepwater developments. Reserves reached an all-time high of 460 MMBoe, 55 percent of our total reserves, primarily through our organic programs and supplemented by smaller acquisitions. North America operations are organized into two regions: Northern and Southern.

The Northern region contains the majority of our North American reserves, almost 75 percent, with our largest single asset company-wide being the Wattenberg field in the DJ basin of Colorado. With thousands of identified projects and a large undeveloped resource potential, Wattenberg is a high quality, long-lived asset acting as an important foundation in our business model. Our Wattenberg assets have also created follow-on opportunities for near-term growth, such as our USX acquisition and our joint venture with Teton Energy Corporation (Teton) in the Eastern DJ basin. In fact, we have completed our initial commitment to drill 20 wells in our joint venture acreage with Teton. Results have been encouraging, and we plan to move forward with additional drilling in 2007 on the 184,000 gross acres covered by the joint venture agreement. The Northern region has a number of other active investment programs that contributed to our growth in 2006, including the Piceance, Wind River and San Juan basins. In the Western Mid-continent, our greatest activity continues to be the Granite Wash development in the Texas Panhandle, where we have several years of locations to be drilled.

Our Southern region, which is comprised of the deepwater Gulf of Mexico, the Gulf Coast and Eastern Mid-continent areas, is a significant contributor in terms of resource potential and production. Almost half of our 2006 North America production came from the Southern region, and our deepwater portfolio offers exposure to high impact exploration. In 2006, we streamlined our asset portfolio in the Southern region by selling our mature Gulf of Mexico shelf assets. These assets were experiencing steep decline rates and provided limited growth opportunities for a company of our size. Most of our North America exploration program is in the Southern region, where we added the Raton and Redrock discoveries in 2006. Development plans for those discoveries are currently under review. In 2006, most of our investment program in the Southern region was focused on completing our deepwater developments. All were completed on time and within budget, with Lorien being the latest development starting up as expected in May. For 2007, we see additional development opportunities at Lorien and Ticonderoga. We also expect to drill another two to four deepwater exploration wells in 2007. We continue with active onshore drilling programs in the Gulf Coast, Oklahoma, Kansas and Illinois.

INTERNATIONAL OVERVIEW

Growth continued in our international operations in 2006, with operating income increasing 36 percent to a record $707 million from $519 million in 2005. Higher commodity prices contributed to increased income, but production also increased to 64,900 Boepd from 62,200 Boepd in 2005.

Our largest area of international operations continues to be Equatorial Guinea, where we have an interest in the Alba field. Operations in Equatorial Guinea generated a record $494 million of operating income. We expect to see significant production increases in Equatorial Guinea in 2007, with natural gas sales to a liquefied natural gas facility expected to start mid-year 2007. These sales are expected to average between 13,000 Boepd and 19,000 Boepd for 2007. Prices for incremental natural gas sales from the Alba field will be similar to those we currently receive there. In 2005, we announced a condensate and natural gas discovery at our offshore Belinda exploration well in Block 'O.' We have numerous other prospects and leads on Block 'O' and the adjacent Block 'I.' With six firm and two optional slots reserved on a drill ship in West Africa, we plan an expanded drilling program in 2007 and 2008 to appraise the Belinda discovery and test several other prospects on both blocks.

Elsewhere in West Africa, we acquired a 50 percent interest in the PH-77 license offshore Cameroon. Noble Energy will operate PH-77, which covers 1.125 million gross acres off the coast of the Republic of Cameroon. Evaluation work is underway, with the intent of identifying drilling locations for 2007 and 2008.

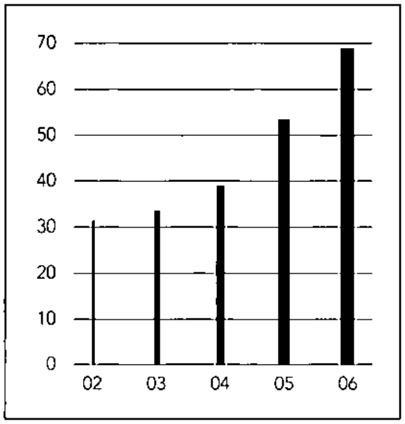
In Israel, our natural gas sales continued to increase in 2006, averaging about 93 million cubic feet per day (MMcfpd), net for the year, a 40 percent increase over 2005. The Israel Electric Corporation, Ltd, our primary customer, continues to convert power plants to burn natural gas, assuring continued growth in demand in 2007 and beyond. In July 2006, we acquired a 33 percent participating interest in two offshore licenses, 308 Michal and 309 Matan. We became the operator for both licenses and plan to drill an exploration well in 2007.

In the North Sea, the Dumbarton development was completed and production began in January 2007. Dumbarton is expected to add approximately 9,000 Boepd, net to Noble Energy's 30 percent interest.

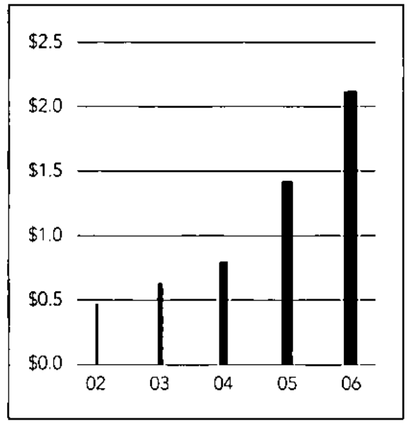
In the Bohai Bay of China, production remained strong throughout 2006, averaging over 4,200 Boepd, net. We have also identified additional field development opportunities and are working to gain approval of a major new phase in the development of the field.

In South America, our natural gas-to-power project in Ecuador produced a record amount of electricity in 2006, generating approximately 866,000 megawatts of power. We also may drill our first exploration well offshore Suriname in late 2007 or early 2008, where we have a 30 percent interest in Block 30.

ANNUAL SALES VOLUMES (MMBoe)



ANNUAL DISCRETIONARY CASH FLOW (BILLIONS)



SUMMARY

I hope it is apparent how dramatic Noble Energy's change has been over these past few years. We believe the business model we have adopted is the best for our company and its shareholders. It takes advantage of the strengths and skills of our employees in continuing to build a high quality portfolio of producing assets and future investment opportunities. Today we believe our foundation is extremely solid, anchored in some of the best natural gas and oil regions in the world. We are pursuing a broad array of development projects that give greater certainty to our near-term growth while focusing our exploration efforts on prospects that can have a material impact on our company for years into the future. Yes – we still have a lot of work to do, but much has been accomplished in the last several years.

In a world where demand for energy continues to grow, all of us at Noble Energy realize that we have very important responsibilities to our shareholders, customers, communities, and host countries. Our primary responsibility is to find and develop natural gas and oil as efficiently as possible, while delivering superior returns to our shareholders. We also recognize that in doing this, we must work to minimize the impacts our operations have on the environment while preserving the safety of all who are involved. It also goes, almost without saying, that compliance with laws and regulations is a given. I am proud that our employees take these responsibilities seriously. They have continued to do an outstanding job in carrying out their work with intensity, integrity and a focus on excellence.

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

CHARLES D. DAVIDSON

Charles D. Davidson

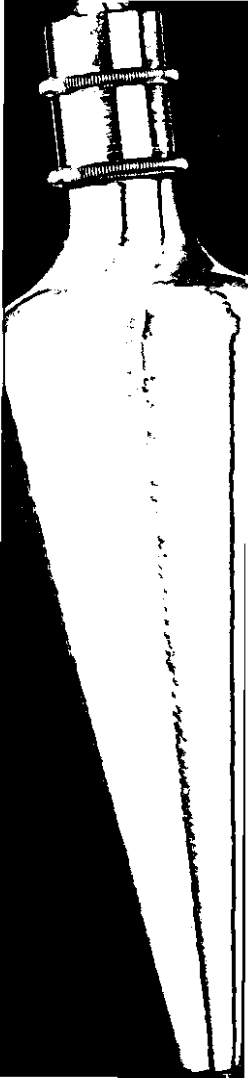
CHAIRMAN OF THE BOARD
PRESIDENT AND CHIEF EXECUTIVE OFFICER

OPERATING & FINANCIAL DATA - 2006 ANNUAL REPORT

OPERATING DATA	2006	2005	2004	2003	2002
Year-End Proved Reserves					
Natural Gas (MMcf)	3,230,814	3,091,219	1,986,861	1,641,920	1,600,801
Crude Oil (MBbls)	296,090	290,830	193,464	183,219	201,478
Total (MBoe)	834,559	806,033	524,607	456,872	468,278
SALES VOLUMES					
Natural Gas (Bcf)	227.4	185.5	134.3	122.9	124.5
Crude Oil (MMBbls) [1]	30.3	22.0	16.6	13.1	10.6
Total (MMBoe)	68.2	52.9	39.0	33.6	31.4
AVERAGE SALES PRICE					
Natural Gas (per Mcf)	$ 5.55	$ 5.78	$ 4.76	$ 4.19	$ 2.89
Crude Oil (per Bbl) [2]	$ 54.47	$ 45.35	$ 34.48	$ 27.67	$ 24.22

FINANCIAL DATA (In thousands, except per share amounts and ratios)	2006	2005	2004	2003	2002
Revenues	$ 2,940,082	$ 2,186,723	$ 1,351,051	$ 1,008,226	$ 703,068
Net Income	$ 678,428	$ 645,720	$ 328,710	$ 77,992	$ 17,652
Basic Earnings per Common Share	$ 3.86	$ 4.20	$ 2.82	$ 0.68	$ 0.15
Basic Weighted Average Common Shares	175,707	153,773	116,550	113,928	114,392
Cash Dividend per Common Share	0.28	0.15	0.10	0.09	0.08
Net Cash Provided by Operating Activities	$ 1,730,306	$ 1,239,878	$ 708,186	$ 602,770	$ 506,955
Capital Expenditures [3]	$ 1,347,116	$ 890,010	$ 628,886	$ 502,073	$ 612,290
Total Assets	$ 9,588,625	$ 8,878,033	$ 3,435,784	$ 2,820,800	$ 2,730,016
Long-term Debt, Net of Current Portion	$ 1,800,810	$ 2,030,533	$ 880,256	$ 776,021	$ 977,116
Stockholders' Equity	$ 4,133,817	$ 3,090,144	$ 1,459,988	$ 1,073,573	$ 1,009,386
Total Debt-to-Book-Capital Ratio	30%	40%	38%	42%	49%
Debt per BOE	$ 2.16	$ 2.52	$ 1.68	$ 1.70	$ 2.09

[1] Includes Sales from Equity Investee Liquids in 2006, 2005 and 2004 of 2.9 MMBbls, 1.2 MMBbls and 0.3 MMBbls, respectively.
[2] Excludes Equity Investee Liquids Sales Volumes and Prices.
[3] Excludes Acquisitions.



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

or

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

For the transition period from to

Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

(Registrant's telephone number, including area code)

(281) 872-3100

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. ☒ Yes ☐ No

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

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

Indicate by check mark 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. ☒

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2006: $8,136,291,163. Number of shares of Common Stock outstanding as of February 12, 2007: 170,405,901.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2007 Annual Meeting of Stockholders to be held on April 24, 2007, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2006, are incorporated by reference into Part III.

TABLE OF CONTENTS

PART I

Items 1 and 2. Business and Properties.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. 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 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 U.S. including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan Basin in New Mexico, the Gulf Coast and the Gulf of Mexico. In addition, we conduct business internationally in West Africa (Equatorial Guinea and Cameroon), the Mediterranean Sea, Ecuador, the North Sea, China, Argentina, and Suriname.

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 domestic and international projects. In 2005, we completed a merger (the "Patina Merger") with Patina Oil & Gas Corporation ("Patina"). In 2006, we acquired U.S. Exploration Holdings, Inc. ("U.S. Exploration") and sold substantially all of our Gulf of Mexico shelf properties, except for the Main Pass area. (See Acquisition and Divestiture Activities.) These transactions have allowed us to achieve a strategic objective of enhancing our U.S. asset portfolio which has resulted in a company with assets and capabilities that include growing U.S. basins coupled with a significant portfolio of international properties. Our 2006 crude oil and natural gas production volume was 29% higher than 2005 and 75% higher than 2004. Our reserve base is balanced between domestic and international sources at 55% domestic and 45% international. We are now a larger, more diversified company with greater opportunities for both domestic and international growth.

Proved Reserves

As of December 31, 2006, we had estimated proved reserves of 3.2 Tcf of natural gas and 296 MMBbls of crude oil. On a combined basis, these proved reserves were equivalent to 835 MMBoe, of which 55% were located in the U.S. and 45% were located internationally. Our proved reserves have increased 4% since December 31, 2005 and 59% over the past three years. At December 31, 2006, 71% of reserves were proved developed reserves.

Proved reserves estimates at December 31, 2006 were as follows:

	December 31, 2006		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
U.S.			
Natural gas (Bcf)	1,255	484	1,739
Crude oil (MMBbls)	115	55	170
Total U.S. (MMBoe)	324	136	460
International			
Natural gas (Bcf)	850	642	1,492
Crude oil (MMBbls)	125	1	126
Total International (MMBoe)	267	108	375
Worldwide			
Natural gas (Bcf)	2,105	1,126	3,231
Crude oil (MMBbls)	240	56	296
Total Worldwide (MMBoe)	591	244	835

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 and Denver offices perform 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 Senior Vice President with responsibility for corporate reserves. During each of the years 2006, 2005 and 2004, 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 extensive 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 2006 included a detailed review of 14 of our major international, deepwater and domestic properties, 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 and domestic properties, which covered approximately 72% of our total proved reserves. The reserve audit for 2004 included a detailed review of 11 of our major international, deepwater and domestic properties, which covered approximately 78% of our total proved reserves.

In connection with the 2006 reserve audit, NSAI performed its own estimates of our proved reserves. In order to perform their 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 properties 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 they had satisfactorily resolved their 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, 2006, based upon their evaluation. Their opinion concluded that our estimates of proved reserves were, in the aggregate, reasonable.

The properties that NSAI audits include our most significant properties and are chosen by senior engineering staff and Division management with final approval by the Senior Vice President with responsibility for corporate reserves. We usually include all deepwater fields, all international properties that require reports by requirement of the host government, all properties that require sanctioning by our Board of Directors, and other major properties. No significant properties were excluded from the December 31, 2006 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 estimates ranged from plus 31,617 MBoe to minus 10,120 MBoe as compared with our estimates. On a percentage basis, the NSAI estimates ranged from 13% above our estimates to 30% 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, 2006, reserves differences, in the aggregate, were less than 9,243 MBoe, or 1%.

Since January 1, 2006, 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 U.S. 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 or 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 maintain a balanced portfolio with high-quality, core properties.

On July 14, 2006, we sold substantially all of our Gulf of Mexico shelf properties except for the Main Pass area, which continues to undergo repair work after suffering significant hurricane damage in 2004 and 2005. As of March 1, 2006, the effective date of the sale, proved reserves for the assets sold totaled approximately 7 MMBbls of crude oil and 110 Bcf of natural gas. Gulf of Mexico deepwater 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.

On March 29, 2006, we acquired U.S. Exploration, a privately held corporation located in Billings, Montana for $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located in Colorado's Wattenberg field. This acquisition significantly expands our operations in one of our core areas. Proved reserves of U.S. Exploration at the time of acquisition were approximately 234 Bcfe, of which 38% were proved developed and 55% 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.

On May 16, 2005 we acquired Patina for a total purchase price of $4.9 billion. Patina's long-lived crude oil and natural gas reserves provide a significant inventory of low-risk opportunities that balanced our portfolio. Patina's proved reserves at the time of acquisition were estimated to be approximately 1.6 Tcfe, of which 72% were proved developed and 67% 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.

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 NGL processing plants and pipeline systems.

North America

We have been engaged in exploration, exploitation and development activities throughout onshore North America 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 regions. These two purchases have provided us with a multi-year inventory of exploitation and development opportunities. North America operations accounted for 65% of our 2006 production volumes and 55% of total proved reserves at December 31, 2006. Approximately 62% of the proved reserves are natural gas and 38% are crude oil. Our onshore North America portfolio at December 31, 2006 included 1,416,429 gross developed acres and 1,343,101 gross undeveloped acres. Offshore, in the Gulf of Mexico, we hold interests in 111 blocks. The following discussion includes activities related to U.S. Exploration properties from March 29, 2006 through December 31, 2006.

Production volumes and estimates of proved reserves for our significant North American operating areas were as follows:

	Year Ended December 31, 2006 Production Volumes			December 31, 2006 Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
Northern Region						
Rocky Mountains:						
Wattenberg	58,324	4,116	13,837	899	77	227
Other	20,001	51	3,385	305	1	52
Western Mid-continent	29,347	377	5,268	340	3	59
Total	107,672	4,544	22,490	1,544	81	338
Southern Region						
Deepwater	17,195	6,417	9,283	77	22	35
Gulf Coast onshore	19,188	1,356	4,554	88	14	29
Gulf of Mexico shelf	18,787	1,370	4,501	13	14	16
Eastern Mid-continent	2,033	3,028	3,367	17	39	42
Total	57,203	12,171	21,705	195	89	122
Total North America	164,875	16,715	44,195	1,739	170	460

Northern Region—The Northern region includes our operations in the Rocky Mountain area as well as activities in the western Mid-continent area. The Rocky Mountain area 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. In the western Mid-continent area (the Texas Panhandle and parts of Oklahoma, Kansas, Arkansas, and Alabama), the area of greatest activity continues to be the Granite Wash development in the Texas Panhandle, where we are continuing with multi-well programs in the Buffalo Wallow and Billy Rose fields. In 2006, we drilled or participated in 649 gross wells in the Northern region. We also performed or participated in 706 deepening, refrac and recompletion projects in this region. Activity in the Northern region, excluding the acquisition of U.S. Exploration, was responsible for 80% of our 2006 company-wide proved reserves additions. We are currently running 13 drilling rigs and 33 completion/workover units. We plan to invest approximately $753 million, or 71% of budgeted domestic capital, on approximately 1,900 projects in the Northern region during 2007.

Wattenberg Field—The Wattenberg field is the most active field in the Northern region. In 2006, daily production from this field averaged 160 MMcf per day and 11 MBbls per day and accounted for 31% of total domestic production volumes. Wattenberg field proved reserves accounted for 49% of domestic proved reserves at December 31, 2006. At December 31, 2006, we had working interests in approximately 4,600 gross (4,089 net) producing crude oil and natural gas wells in the Wattenberg field.

We acquired working interests in the Wattenberg field through the Patina Merger and acquisition of U.S. Exploration. 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. In a section 4,500 feet thick, there may be up to eight potentially productive formations. Three of the formations, the Codell, Niobrara and J-Sand, are considered "blanket" zones in the area of our holdings, while others, such as the D-Sand, Dakota and the shallower Shannon, Sussex and Parkman, are more localized. While these zones may be present, any particular property's productivity is dependent on the reservoir properties peculiar to its location. Such productivity may be uneconomic. Our operated working interest at December 31, 2006 was approximately 97%.

Drilling in the Wattenberg field is considered lower risk from the perspective of finding crude oil and natural gas reserves, with 100% of the wells drilled in 2006 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 26 completion units in the Wattenberg field. Our current field activities are focused primarily on the development of J-Sand and Codell reserves through drilling new wells or deepening within existing wellbores, recompleting the Codell formation within existing J-Sand wells, refracing or trifracing existing Codell wells and refracing or recompleting the Niobrara formation within existing Codell wells. A refrac consists of the restimulation of a producing formation within an existing wellbore to enhance production and add incremental reserves. These projects and continued success with our production enhancement program, along with the U.S. Exploration acquisition, allowed us to increase production and add proved reserves to what is considered a mature field. During 2006, we added approximately 223 Bcfe of proved reserves in the Wattenberg field, approximately 63% of which was natural gas, and grew production from an average of 124 MMcfe per day for 2005 to 227 MMcfe per day for 2006.

During 2006, we drilled or participated in 48 wells and deepened nine wells to the J-Sand formation in the Wattenberg field. We plan to drill or deepen approximately 107 wells to the J-Sand in 2007.

We performed or participated in 179 Codell refracs in the Wattenberg field during 2006. We plan to perform approximately 46 Codell refrac projects in 2007.

We performed or participated in 160 Codell trifracs in the Wattenberg field during 2006. The trifrac program, which is effectively a refrac of a refrac, continues to have encouraging results. We plan to perform approximately 150 trifracs in 2007.

We performed or participated in 294 Niobrara recompletions in the Wattenberg field during 2006. We plan to perform approximately 554 Niobrara projects in 2007.

We also performed or participated in 38 Codell recompletions and drilled or participated in 259 Codell wells in the D-J Basin in 2006. We plan to drill or participate in 513 Codell wells and 30 Codell recompletions in 2007.

During 2006, numerous projects, including well workovers, reactivations, and commingling of zones, were performed. These projects, combined with the new drills, deepenings and refracs, were an integral part of the 2006 Wattenberg field development program. We had a significant inventory of these projects at year-end 2006.

Other Rocky Mountain areas include:

Piceance Basin—The Piceance Basin in western Colorado is another rapidly growing area for us. We have a 9,258-acre (gross) position and are currently running two drilling rigs and one completion unit. We drilled or participated in 49 development wells during 2006, all of which were successful. Our 2006 activity resulted in the addition of 77 Bcfe of proved reserves. Average daily production was 7.5 MMcfe per day in 2006. We plan to drill 74 wells during 2007. Our working interest at December 31, 2006 was approximately 89%.

San Juan Basin—The San Juan Basin is located in northwestern New Mexico and southwestern Colorado. During 2006 we drilled or participated in 12 development wells, all of which were successful. Our operated working interest at December 31, 2006 was approximately 80%.

Niobrara Trend—The Niobrara trend is located in eastern Colorado and extends into Kansas and Nebraska. We drilled or participated in 99 development wells with a 91% success rate during 2006. The wells drilled included 20 commitment wells drilled pursuant to an acreage earning agreement with Teton Energy Corporation. Under the terms of the agreement, we earned a 75% working interest in approximately 184,000 acres in the D-J Basin by drilling the commitment wells. Going forward, we will split all costs associated with future drilling according to each party's working interest. The acreage included in this agreement is a potential eastward extension of the Niobrara producing trend in Yuma County, Colorado. We plan to drill 150 wells in the Niobrara Trend in 2007, including 90 on the Teton acreage. Our overall operated working interest in the Niobrara Trend at December 31, 2006 was approximately 96%.

Bowdoin Field—The Bowdoin field is located in north central Montana. During 2006, we drilled or participated in 25 development wells, all of which were successful. We plan to drill 25 new wells and recomplete 150 wells during 2007. Our operated working interest at December 31, 2006 was approximately 65%.

Wind River Basin—At Iron Horse in the Wind River Basin located in central Wyoming, we drilled or participated in six wells in 2006. We plan to drill eight wells during 2007. Our operated working interest at December 31, 2006 was approximately 57%.

Western Mid-continent areas include:

Buffalo Wallow—A significant area of activity in our Northern region is the Buffalo Wallow field, located in the Texas Panhandle. The primary producing horizons, which generally produce natural gas, are comprised of various intervals in the Granite Wash sequence at approximately 11,000 feet. The productive intervals include a series of stratigraphically trapped sands with an average gross interval of 700 feet. The field has historically been developed on 40-acre spacing. In late 2004, the Texas Railroad Commission approved down-spacing of the field to allow development on 20-acre locations. We drilled or participated in 98 development wells in the Buffalo Wallow field in 2006, all of which were successful. Our 2006 activity resulted in the addition of 53 Bcfe of proved reserves. We plan to drill 60 wells during 2007. Our operated working interest at December 31, 2006 was approximately 85%.

Billy Rose—The Billy Rose field is also located in the Texas Panhandle. During 2006, we drilled or participated in 18 development wells, all of which were successful. We plan to drill 12 wells during 2007. Our operated working interest at December 31, 2006 was approximately 85%.

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 eastern Mid-continent area (Oklahoma, Kansas, Illinois and Indiana). The Gulf Coast and deepwater Gulf of Mexico are core domestic operating areas. Activity in the Southern region was responsible for approximately 18% of our 2006 company-wide proved reserves additions. During 2006, we sold essentially 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 nearby onshore Gulf Coast and deepwater Gulf of Mexico which are areas of higher potential. We plan to invest approximately $306 million, or 29% of budgeted domestic capital, in the Southern region during 2007, with approximately 60% in the deepwater Gulf of Mexico, and the remaining equally to the Gulf Coast and the eastern Mid-continent areas.

Deepwater—During 2006, we continued to focus on the growth of our deepwater Gulf of Mexico business, bringing three new subsea development projects online between December 2005 and April 2006. Cycle time from project sanction to first production was 19 months or less for each of these three projects.

Additionally, we drilled two operated exploration wells and one operated exploration appraisal well. We have committed to an additional 24-month exclusive term for the Ocean Quest deepwater drilling rig owned by Diamond Offshore, and committed to an initial 18-month term for use of the Ensco 8501 dynamically-positioned deepwater rig currently under construction and scheduled for service in 2009.

Three new deepwater developments are on stream. Swordfish (Viosca Knoll Block 917, 961, and 962) is a 2001 deepwater discovery, located in approximately 4,500 feet of water and consisting of three subsea wells tied back via dual flowlines to Anadarko's Neptune spar in Viosca Knoll Block 826. We are the operator on Swordfish. Swordfish achieved first production December 2005. Ticonderoga (Green Canyon Block 768) is a 2004 deepwater discovery, located in approximately 5,300 feet of water and consisting of 2 subsea wells tied back to Anadarko's Constitution spar in Green Canyon Block 680. We have a non-operated position in the development. Ticonderoga achieved first production February 2006. Lorien (Green Canyon Block 199) is a 2003 deepwater discovery, located in approximately 2,200 feet of water and consisting of two subsea wells tied back to the Green Canyon 65 platform. We are the operator on Lorien. Lorien achieved first production April 2006.

We had two deepwater discoveries in 2006. Redrock (Mississippi Canyon Block 204 #1) drilled to a total measured depth of 23,365 feet and is located in 3,334 feet of water. The well encountered high quality hydrocarbon pay and is under review to determine commerciality. We are operator for Redrock. Raton (Mississippi Canyon Block 248 #1) drilled to a total measured depth of 20,106 feet and is located in approximately 3,400 feet of water. Plans are to sidetrack and complete this well and begin a subsea tieback to a nearby host during 2007 with anticipated first production in 2008. A second well at Raton (Mississippi Canyon 292 #5) was drilled during 2006 to appraise deeper shows seen in the 248 #1 well. The 292 #5 well was temporarily abandoned and is pending final commercial evaluation. We are operator for Raton.

We were successful in two lease sales during 2006, winning eight new deepwater leases totaling $14.5 million, net, in the Central and Western planning areas, all operated leases. We expanded our deepwater exploration geoscience staff and regional 3D seismic database to help fuel inventory growth through future lease sales. Aggressive expansion of the seismic database will continue during 2007.

Deepwater Gulf of Mexico accounted for 21% of 2006 domestic production volumes and 8% of domestic proved reserves at December 31, 2006.

Gulf Coast Onshore—During 2006, we drilled or participated in 56 wells. Of these 56 wells, 13 were in the Noble-operated South Central Robertson Unit located in West Texas, which increased production 432 Bopd from the previous year. Our 2006 activity resulted in the addition of 34 Bcfe of proved reserves. We plan to drill or participate in 36 wells during 2007. The Gulf Coast onshore accounted for 10% of 2006 domestic production volumes and 6% of domestic proved reserves at December 31, 2006.

Gulf of Mexico Shelf—The Gulf of Mexico Shelf accounted for 10% of 2006 domestic production volumes. Substantially all of these non-core assets were sold during 2006.

Eastern Mid-continent areas include:

Central Oklahoma—During 2006, we drilled or participated in 110 wells, 107 of which were successful. We plan to drill 64 wells during 2007.

Illinois/Indiana—We drilled or participated in 31 development wells in 2006, 29 of which were successful. We plan to drill or participate in 43 wells in Illinois in 2007.

Other—During 2006, we drilled or participated in an additional 20 wells in the Southern region including wells drilled in Kansas and other parts of Oklahoma.

Shale Plays—We continue to selectively increase our acreage position in resource plays, including shale plays. We have accumulated over 186,000 acres in the New Albany, Caney, Fayetteville and Floyd shales.

We continue to evaluate three New Albany Shale wells drilled in the Illinois basin. Additional New Albany wells are being considered in the first quarter of 2007 to provide additional data in evaluating project potential.

International

Our international operations are significant to our business, accounting for 35% of consolidated production volumes in 2006, and 45% of total proved reserves at December 31, 2006. International proved reserves are approximately 66% natural gas and 34% crude oil. Operations in Equatorial Guinea, Cameroon, Ecuador and China are conducted in accordance with the terms of production sharing contracts.

International production volumes and estimates of proved reserves were as follows:

	Year Ended December 31, 2006			December 31, 2006		
	Production Volumes			Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
International						
West Africa	16,579	6,519	9,282	945	90	248
North Sea	2,967	1,357	1,852	19	19	22
Israel	33,906	—	5,651	360	—	60
Ecuador	8,933	—	1,489	168	—	28
China	—	1,539	1,539	—	9	9
Argentina	108	1,213	1,231	—	8	8
Total consolidated	62,493	10,628	21,044	1,492	126	375
Equity investees:						
Condensate (MBbls)	—	634	634			
LPG (MBbls)	—	2,297	2,297			
Total	62,493	13,559	23,975			
Equity investee share of methanol sales (Kgal)			109,942			

West Africa (Equatorial Guinea and Cameroon)—Our operations in Equatorial Guinea accounted for 51% of 2006 international production volumes and 66% of international proved reserves at December 31, 2006. At December 31, 2006, we held 45,376 gross developed acres and 850,395 gross undeveloped acres in Equatorial Guinea and 1,125,000 gross undeveloped acres in Cameroon.

We began investing in Equatorial Guinea in the early 1990's. Activities center around our 34% working interest in the offshore Alba field, which is one of our most significant assets. Operations include the Alba field and related methanol plant (located on Bioko Island), onshore LPG processing plant, and condensate production facilities. With the completion of expansion projects (Phase 2A and 2B), the current condensate capacity is 21,000 Bpd, net to our interest, and the current LPG capacity is 5,600 Bpd, net to our interest. The methanol plant was originally designed to produce commercial grade methanol at a rate of 2,500 MTpd. As a result of various upgrade efforts, the plant is now capable of producing up to 3,000 MTpd.

We sell our share of natural gas production from the Alba field to the LPG plant and the methanol plant. The LPG plant is owned by Alba Plant LLC, in which we have a 28% interest, accounted for by the equity method. The LPG plant purchases natural gas from the Alba field under an annual contract. 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 domestic and international customers. In addition, we, along with Marathon Oil Corporation (our Alba field partner) and GEPetrol (the national oil company of Equatorial Guinea), have entered into a natural gas sales contract with an LNG plant currently under construction. The contract runs through 2023. The LNG plant is expected to begin production in 2007. We have no ownership interest in the LNG plant. We sell our share of condensate produced in the Alba field and from the LPG plant under short-term contracts at market-based prices. We have a direct ownership interest of 34% in the condensate production facilities.

In 2005, we expanded our activities in Equatorial Guinea with exploration activities in Blocks O and I (45% and 40% working interest, respectively) on which we are the technical operator. In October 2005, we announced a discovery on Block O with successful test results from the O-1 ("Belinda") exploration well, and during 2006, we continued exploration work on Blocks O and I. We have contracted a rig and expect to begin a drilling program on these blocks, consisting of four wells, during 2007, with drilling scheduled to begin on Block O.

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.

During 2006, we acquired a 50% participating interest in the PH-77 license, offshore the Republic of Cameroon, on which we are the operator. We expect to drill one exploration well on this acreage in 2007.

We plan to invest approximately $145 million, or 51% of budgeted international capital, in West Africa in 2007.

Israel—Our operations in Israel accounted for 24% of 2006 international production volumes and 16% of international proved reserves at December 31, 2006. At December 31, 2006, we held 123,552 gross developed acres and 468,264 gross undeveloped acres located about 20 miles offshore Israel in water depths ranging from 700 feet to 5,000 feet. Our exploration agreement in Israel covers three licenses and two leases 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. Natural gas sales began in 2004 and have been increasing steadily as the Israel natural gas infrastructure has developed. The Israel Electric Corporation Limited (IEC) is our largest purchaser, and sales of natural gas to the Reading power plant in Tel Aviv commenced second quarter 2006. Sales to the Bazan Oil Refinery also began in 2005. Our 2006 gas production volume (93 MMcfpd) was 40% higher than 2005 and almost double 2004 production volume. Onshore pipeline construction is underway, which should allow the IEC power plants at Gezer and Hagit, along with the Delek IPP and associated desalinization plant, and a paper mill to consume gas by the end of 2007.

During 2007 we will complete construction of a permanent onshore receiving terminal for distribution of natural gas from the Mari-B field to purchasers. Currently, we are drilling an additional well in the Mari-B field (Mari-B #7) to further enhance field deliverability. In 2006, we acquired a 33% participating interest in additional exploration acreage offshore northern Israel. We are in the process of securing a rig and intend to drill one exploration well on this acreage in 2007.

North Sea—Our operations in the North Sea (the Netherlands, Norway and the UK) accounted for 8% of 2006 international production volumes and 6% of international proved reserves at December 31, 2006. At December 31, 2006, we held 42,822 gross developed acres and 574,293 gross undeveloped acres.

Our operations in the North Sea comprise another core international asset, and we have been conducting business there since 1996. We have working interests in 17 licenses with working interests ranging from 7% to 100% and are the operator of three blocks. During 2006 we continued to make progress on the non-operated Dumbarton development (30% working interest) in Blocks 15/20a and 15/20b in the UK sector of the North Sea. Dumbarton is a re-development of the Donan Field and is located in 140 meters of water, 225 kilometers northeast of Aberdeen, Scotland. Development included the drilling of six development wells in 2006 and subsea tie-back to the GP III, a floating production, storage and offloading vessel in which we own a 30% interest. First production commenced in January 2007.

In 2007, in addition to bringing the Dumbarton development on production, exploration efforts will continue as we and our partners finish an appraisal well on the Flyndre Block (22.5% working interest) and begin exploration efforts at Selkirk (30.5% working interest). We plan to invest approximately $73 million, or approximately 5% of budgeted capital, in the North Sea during 2007.

In January 2007, we were successful in obtaining a 40% participating interest in Norwegian License PL 406 and a 20% participating interest in Norwegian License PL 407. Combined, these license areas cover portions of 11 offshore Norway blocks encompassing approximately 1,640 square kilometers. We are establishing an office in Norway and will begin working with the operator of each license area to further study this acreage.

Ecuador—Our operations in Ecuador accounted for 6% of 2006 international production volumes and 7% of international proved reserves at December 31, 2006. 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 2006, the power production totaled 865,983 MW.

China—Our operations in China accounted for 6% of 2006 international production volumes and 2% of international proved reserves at December 31, 2006. At December 31, 2006, we held 7,413 gross developed acres and no undeveloped acres in China.

We have been engaged in exploration and development activities in China since 1996. We are operator of the Cheng Dao Xi field (57% working interest), which is located in the shallow water of the southern Bohai Bay. Production began in 2003. During 2006, we completed two additional development wells which are now contributing to production and added almost 2 MMBbls in proved reserves. Our share of crude oil production is sold into the local Chinese market pursuant to a long-term contract at market-based prices.

In 2007 we will 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.

Argentina—Our operations in Argentina accounted for 5% of 2006 international production volumes and 2% of international proved reserves at December 31, 2006. At December 31, 2006, we held 113,325 gross developed acres and no undeveloped acres in Argentina.

We have conducted business in Argentina since 1996. Our producing properties are located in southern Argentina in the El Tordillo field (13% working interest), which is characterized by secondary recovery crude oil production. During 2006, we participated in the drilling of 58 gross (7.6 net) development wells in the El Tordillo field and plan to continue development drilling in 2007.

Suriname—Suriname, a country located on the northern coast of South America, represents a new exploration project for us. In 2005 we entered into a participation agreement on Block 30 (30% working interest). Block 30 (non-operated) covers approximately 4.6 million acres with two-thirds of the block in water depth greater than 600 feet. A seismic program was completed in 2006 and interpretation work is currently underway.

Production Volumes, Price and Cost Data—Production volumes, price and cost data for continuing operations are as follows:

	Production 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, 2006					
U.S.	164,875	16,715	$6.61	$50.68	$ 8.12
West Africa [4]	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 [5]	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 [6]	—	2,931	—	45.83	—
Total	227,368	30,274	$5.55	$53.64	
Year Ended December 31, 2005					
U.S.	125,543	9,468	$7.43	$46.67	$ 7.39
West Africa [4]	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 [5]	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 [6]	—	1,183	—	43.43	—
Total	185,492	21,973	$5.78	$45.25	
Year Ended December 31, 2004					
U.S.	88,077	7,951	$6.03	$32.64	$ 5.84
West Africa [4]	16,747	3,364	0.25	38.16	3.38
North Sea	4,130	2,459	4.73	38.90	6.13
Israel	17,573	—	2.78	—	2.46
Other International [5]	7,782	2,506	0.75	31.06	5.67
Total Consolidated Operations	134,309	16,280	4.76	34.48	5.20
Equity Investee [6]	—	327	—	32.01	—
Total	134,309	16,607	$4.76	$34.44	$ —

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

(2) Average natural gas sales prices for the U.S. reflect reductions of $0.25 per Mcf (2006), $0.77 per Mcf (2005) and $0.08 per Mcf (2004) from hedging activities. Average crude oil sales prices for the U.S. reflect reductions of $11.41 per Bbl (2006), $8.03 per Bbl (2005) and $3.05 per Bbl (2004) from

hedging activities. Average crude oil sales prices for Equatorial Guinea reflect a reduction of $9.93 (2005) from hedging activities.

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

(4) Natural gas in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant through 2026 and annually to an LPG plant. Sales from the Alba field to these plants are based on a BTU equivalent and then converted to a dry gas equivalent volume. Both of these 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 2006, the price on an Mcf basis has been adjusted to reflect the Btu content of gas sales.

(5) Other International natural gas production volumes include Ecuador and Argentina. Although Ecuador natural gas production volumes are included in Other International production, they are excluded from average natural gas sales prices. The natural gas-to-power project in Ecuador is 100% owned by us, and intercompany natural gas sales are eliminated. Natural gas production volumes associated with the gas-to-power project were 8,933 MMcf for 2006, 8,320 MMcf for 2005, and 7,640 MMcf for 2004. Other International oil production includes China and Argentina.

(6) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 6,294 Bopd, 2,328 Bopd, and 706 Bopd for 2006, 2005, and 2004, respectively.

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, 2006, we operated properties accounting for approximately 66% 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, 2006 is as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States—Onshore	7,326	5,635.7	4,324	2,904.2	11,650	8,539.9
United States—Offshore	110	47.5	9	5.1	119	52.6
International	782	108.4	31	12.8	813	121.2
Total	8,218	5,791.6	4,364	2,922.1	12,582	8,713.7

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.

The following table summarizes multiple completions and non-producing wells as of December 31, 2006. Included in non-producing wells are productive wells awaiting additional action, pipeline connections or shut-in for various reasons.

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Multiple Completions	8	5.9	14	3.6	22	9.5
Non-producing (Shut-in)	1,921	1,279.9	346	257.7	2,267	1,537.6

Developed and Undeveloped Acreage—The developed and undeveloped acreage (including both leases and concessions) held at December 31, 2006 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
U.S.:				
Onshore	1,416,429	794,257	1,343,010	780,622
Offshore	173,105	96,867	486,698	227,601
Total U.S.	1,589,534	891,124	1,829,708	1,008,223
Israel	123,552	58,142	468,264	195,660
Argentina	113,325	15,548	—	—
Equatorial Guinea	45,376	15,727	850,395	299,428
Cameroon	—	—	1,125,000	562,500
Suriname	—	—	4,596,160	1,378,848
Ecuador	12,355	12,355	851,771	851,771
North Sea [1]	42,822	3,921	574,293	243,692
China	7,413	4,225	—	—
Total International	344,843	109,918	8,465,883	3,531,899
Total Worldwide [2]	1,934,377	1,001,042	10,295,591	4,540,122

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

(2) If production is not established, approximately 217,932 gross acres (102,927 net acres), 535,025 gross acres (244,217 net acres), and 375,147 gross acres (152,530 net acres) will expire during 2007, 2008 and 2009, respectively.

Developed acreage is acreage spaced or assignable to productive wells. 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 for each of the last three fiscal years were as follows:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year Ended December 31, 2006						
U.S.	6.3	9.0	15.3	666.6	5.5	672.1
North Sea	—	0.4	0.4	1.8	—	1.8
China	—	—	—	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						
U.S.	4.7	10.7	15.4	488.1	25.9	514.0
Equatorial Guinea	—	—	—	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
Year Ended December 31, 2004						
U.S.	10.7	8.5	19.2	62.4	8.7	71.1
Equatorial Guinea	—	0.3	0.3	2.4	—	2.4
North Sea	0.3	0.7	1.0	0.1	—	0.1
China	—	—	—	1.7	—	1.7
Argentina	—	—	—	10.0	—	10.0
Ecuador	—	—	—	3.0	—	3.0
Total	11.0	9.5	20.5	79.6	8.7	88.3

A productive well is an exploratory or development well that is not a dry hole. A dry hole is an exploratory or development well determined to be incapable of producing either crude oil or natural 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.

At December 31, 2006, we were drilling or completing 171 gross (143.0 net) development wells and 13 gross (6.7 net) exploration wells. These wells are located onshore in Argentina and North America (Alabama, Colorado, Illinois, Indiana, Kansas, Louisiana, Nebraska, Oklahoma, Texas and Wyoming) and offshore Gulf of Mexico and Israel. The drilling cost of these wells will be approximately $99 million if all are dry and approximately $159 million if all are completed as producing wells.

Marketing Activities

Natural Gas Marketing

Natural gas produced in the U.S. is sold 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. At December 31, 2006, approximately 24% of natural gas production was made pursuant to long-term contracts.

Crude Oil and Condensate Marketing

Crude oil and condensate produced in the U.S. 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. Crude oil and condensate are distributed through pipelines and by trucks or tankers to gatherers, transportation companies and end-users.

Noble Energy Marketing, Inc.

We market portions of our domestic natural gas production through Noble Energy Marketing, Inc. ("NEMI"), a wholly-owned subsidiary. NEMI seeks opportunities to enhance the value of our domestic natural gas production by marketing directly to end-users and aggregating natural gas to be sold to natural gas marketers and pipelines. NEMI also engages in the purchase and sale of third-party crude oil and natural gas production. Such third-party production may be purchased from non-operators who own working interests in our wells or from other producers' properties in which we own no interest. We have a long-term natural gas sales contract with NEMI, whereby we receive an index price for all natural gas sold to NEMI. The contract does not specify scheduled quantities or delivery points and expires on May 31, 2009. We sold approximately 43% of our domestic natural gas production to NEMI in 2006.

Significant Purchaser

Trafigura Beheer B.V. ("Trafigura") was the largest single non-affiliated purchaser of 2006 production. Trafigura purchased our share of condensate from the Alba field in Equatorial Guinea and a portion of our share of crude oil in Argentina. Sales to Trafigura accounted for 28% of 2006 crude oil sales, or 15% of 2006 total oil and gas sales. Shell Trading (US) Company accounted for 18% of 2006 crude oil sales, or approximately 10% of total oil and gas sales, and purchased a portion of our share of North America crude oil production. No other single non-affiliated purchaser accounted for 10% or more of oil and gas sales in 2006. 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 2006. Prices for crude oil and natural gas are affected by a variety of factors that are 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

Governmental 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 U.S. 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 its costs of doing business and consequently affects our profitability.

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 U.S. 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 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 any differently, or 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 exploration, development and production: U.S., West Africa, North Sea, Israel, and Other International, Corporate and Marketing. For more information, see Item 8. Financial Statements and Supplementary Data—Note 15—Geographical Data.

Employees

Our total number of employees increased during the year from 1,171 at December 31, 2005 to 1,243 at December 31, 2006. The 2006 year-end employee count includes 121 foreign nationals working as employees in Ecuador, China, Israel, the UK and Equatorial Guinea.

Offices

Our principal corporate office, including our offices for domestic and international operations, is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. We maintain additional offices in Ardmore, Oklahoma and Denver, Colorado and in China, Cameroon, Ecuador, Equatorial Guinea, Israel and the UK.

Title to Properties

We believe that our title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that are not so material as to detract substantially from the value of the interests or materially interfere with their use in our operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under production sharing contracts or exploration licenses.

Available Information

Our website address is *www.nobleenergyinc.com*. Available on this website under "Investor Relations—Investor Relations Menu—SEC Filings," free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and 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 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 also 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 2006, we submitted the annual certification of our Chief Executive Officer regarding compliance with the NYSE's corporate governance listing standards, pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

Item 1A. Risk Factors.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. 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;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- 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. 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 exploration, development and acquisition activities require substantial capital expenditures. 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.

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. 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.

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

We have significant international crude oil and natural gas operations. These operations may be adversely affected by political and economic developments, including the following:

- war, terrorist acts and civil disturbances, such as currently occurring in Israel and other countries in the Middle East;
- 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 new hydrocarbons law recently enacted by the government of Equatorial Guinea;
- changes in taxation policies, including the effects of additional oil profits taxes recently imposed by China and Ecuador and the increase in the Supplementary Charge imposed by the UK on North Sea income;
- laws and policies of the United States and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- foreign exchange restrictions;
- international monetary fluctuations; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

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 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 and the Clean Water Act. Environmental laws and regulations change frequently and the implementation of new, or the modification of existing, laws or regulations could harm us. 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.

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

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment and supplies are substantially greater and their availability may be limited. 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 has risen and the costs of these services are increasing, while the quality of these services may suffer. 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, either because 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; and
- seeking to acquire the equipment and expertise necessary to operate and develop properties.

Many of our competitors have financial and other resources substantially in excess of those available to us. 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, 2006, we had long-term indebtedness of $1.805 billion, with $1.155 billion drawn under our bank credit facility. Our long-term indebtedness represented 30% of our total book capitalization at December 31, 2006.

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 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.

Provisions in our Certificate of Incorporation, Stockholder Rights Plan 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. We also have a stockholder rights plan, commonly known as a "poison pill," that entitles our stockholders to acquire additional shares of our company, or a potential acquirer of our company, at a substantial discount from market value in the event of an attempted takeover without the approval of our Board. Finally, 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 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" and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

The ruling by the Colorado Supreme Court in *Rogers v. Westerman Farm Co.* in July 2001 resulted in uncertainty regarding the deductibility of certain post-production costs from payments to be made to royalty interest owners. In January 2003, Patina was named as a defendant in a lawsuit, which plaintiff sought to certify as a class action, based upon the *Rogers* ruling alleging that Patina had improperly deducted certain costs in connection with its calculation of royalty payments relating to its Wattenberg field operations and seeking monetary damages *(Jack Holman, et al v. Patina Oil & Gas Corporation; Case No. 03-CV-09; District Court, Weld County, Colorado)*. In May 2004, the plaintiff filed an amended complaint narrowing the class of potential plaintiffs, and thereafter filed a motion seeking to certify the narrowed class as described in the amended complaint. Patina filed an answer to the amended complaint. A motion seeking class certification was heard on September 22, 2005 and granted on October 13, 2005. The Colorado Supreme Court denied our petition for review on November 23, 2005. The matter was set for trial scheduled to commence April 24, 2007. In October 2006, we received service in an additional lawsuit styled *Wardell Family Partnership and Glen Droegemueller v. Noble Energy, Inc. et al; Case No. 06-CV-734, District Court, Weld County, Colorado*, involving royalty and overriding royalty interest owners in the same field and not a member of the *Holman* class. The plaintiffs sought to certify the lawsuit as a class action and allegations were made of a similar nature as the *Holman* lawsuit. An answer was timely filed. Through a mediation process, we and the attorneys representing the *Holman* class and *Wardell* putative class have entered into an agreement in principle to settle both cases, and the April 24, 2007 trial date in the *Holman* lawsuit has been vacated. Such a settlement will have to be approved by the Court with notice of the settlement going to all members of the *Holman* class and *Wardell* putative class.

The Illinois Environmental Protection Agency (IEPA) issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. Elysium Energy, LLC acquired Equinox, and Elysium subsequently was acquired by Patina. The facility is a small amine-processing unit used to treat and remove hydrogen sulfide from natural gas prior to transportation. The notice of violation alleges violation of permit requirements under the Clean Air Act dating back to 1986 as well as excessive hydrogen sulfide emissions at the plant. We are cooperatively working with the IEPA staff to address this matter and have received a permit to allow the installation of remediation equipment. On January 17, 2007, the IEPA re-issued written notices of these alleged violations in the name of Equinox's successors in interest, and our subsidiaries, Elysium and Noble Energy Production, Inc. No action will be pursued against Equinox. On February 12, 2007, a compliance commitment agreement was submitted to the IEPA wherein Noble Energy Production and Elysium have agreed to pay a late permit fee, install an incineration/caustic scrubber emissions control system at the site, and fund a supplemental environmental project in the nearby community. The matter will remain open until the emissions control system is constructed and operating within IEPA parameters, which is not expected to occur until the third quarter of 2007.

We are involved in various legal proceedings, including the foregoing matters, in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. The company is defending itself vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our consolidated financial position, results of operations or cash flows.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2006.

Executive Officers

The following table sets forth certain information, as of February 23, 2007, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	56	Chairman of the Board, President, Chief Executive Officer and Director
David L. Stover (2)	49	Executive Vice President, Chief Operating Officer
Chris Tong (3)	50	Senior Vice President, Chief Financial Officer
Alan R. Bullington (4)	55	Senior Vice President, International
Robert K. Burleson (5)	49	Senior Vice President, Business Administration and President, Noble Energy Marketing, Inc.
Susan M. Cunningham (6)	51	Senior Vice President, Exploration and Corporate Reserves
Arnold J. Johnson (7)	51	Vice President, General Counsel and Secretary

(1) Charles D. Davidson was elected President and Chief Executive Officer of Noble Energy in October 2000 and Chairman of the Board in April 2001. Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From

September 1993 to March 1997, he served as a Senior Vice President of Vastar. From 1972 to October 1993, he held various positions with ARCO.

(2) David L. Stover was elected Executive Vice President and Chief Operating Officer of Noble Energy on August 1, 2006 and is currently responsible for all of Noble Energy's exploration and production activities. Prior thereto, he served as Senior Vice President of Noble Energy responsible for the North America Division from July 2004 through July 2006. He served as Noble Energy's Vice President of Business Development from December 2002 through June 2004. Previous to his employment with Noble Energy, he was employed by BP America, Inc. as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar, as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999. From 1979 to 1994, he held various positions with ARCO.

(3) Chris Tong was elected a Senior Vice President and Chief Financial Officer of Noble Energy on January 1, 2005. Prior to January 1, 2005, he had served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. since August 1997. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions since August 1996, and served in other treasury positions with Tejas beginning August 1989. From 1980 to 1989, Mr. Tong served in various energy lending capacities with several commercial banking institutions. Prior to his banking career, Mr. Tong served over a year with Superior Oil Company as a Reservoir Engineering Assistant.

(4) Alan R. Bullington was elected a Vice President of Noble Energy on April 24, 2001 and a Senior Vice President of Noble Energy on July 27, 2004 and is currently responsible for Noble Energy's International Division. Prior thereto, he served as Vice President and General Manager, International Division of Samedan Oil Corporation beginning January 1, 1998. Prior thereto, he served as Manager-International Operations and Exploration and as Manager-International Operations. Prior to his employment with Samedan in 1990, he held various management positions within the exploration and production division of Texas Eastern Transmission Company.

(5) Robert K. Burleson was elected a Senior Vice President of Noble Energy on July 27, 2004 and is currently responsible for Business Administration. Prior thereto, he served as Vice President of Noble Energy since April 24, 2001 and has been responsible for Business Administration since April 2002. He has also served as President of Noble Gas Marketing, Inc. (now Noble Energy Marketing, Inc.) since June 14, 1995. Prior thereto, he served as Vice President-Marketing for Noble Gas Marketing since its inception in 1994. Previous to his employment with Noble Energy, he was employed by Reliant Energy as Director of Business Development for its interstate pipeline, Reliant Gas Transmission.

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

(7) Arnold J. Johnson was elected Vice President, General Counsel and Secretary of Noble Energy on February 1, 2004. Prior thereto, he served as Associate General Counsel and Assistant Secretary of Noble Energy from January 2001 through January 2004. Previous to his employment with Noble Energy, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar from 1997 through 2000. From 1980 to March 1989, he held various positions with ARCO.

PART II

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

Common Stock. Our common stock, $3.33 1/3 par value, is listed and traded on the NYSE under the symbol "NBL." The declaration and payment of dividends are at the discretion of our Board of Directors and the amount thereof will depend on our results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

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

	High	Low	Dividends Per Share
2005			
First quarter	$34.35	$28.06	$0.025
Second quarter	39.22	31.66	0.025
Third quarter	47.52	38.81	0.050
Fourth quarter	47.79	35.96	0.050
2006			
First quarter	$46.91	$38.32	$0.050
Second quarter	49.33	36.14	0.075
Third quarter	51.71	41.80	0.075
Fourth quarter	54.64	41.77	0.075

On January 23, 2007, the Board of Directors declared a quarterly cash dividend of 7.5 cents per common share, which was paid February 20, 2007 to shareholders of record on February 5, 2007.

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

Stockholders' Profile. Pursuant to the records of the transfer agent, as of February 12, 2007, the number of holders of record of common stock was 860.

Stock Repurchases. The following table summarizes repurchases of common stock occurring fourth quarter 2006.

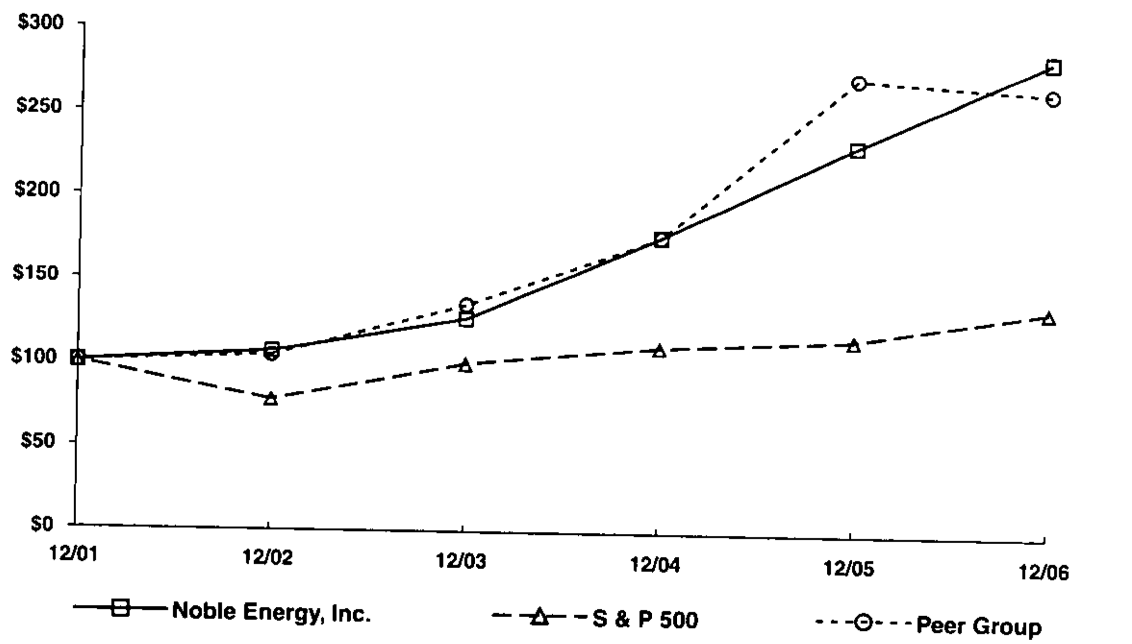
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [1]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
10/01/06—10/31/06	1,664,700	$46.58	1,664,700	
11/01/06—11/30/06	1,387,300	49.46	1,387,300	
12/01/06—12/31/06	1,164,600	51.35	1,164,600	
Total	4,216,600	$48.84	4,216,600	$ 101,493

[1] On May 16, 2006, we announced that our Board of Directors had authorized the repurchase of up to $500 million of common stock. We may buy shares from time to time on the open market or in negotiated purchases. The timing and amounts of any repurchases will be at management's discretion and in accordance with securities laws and other legal requirements. The repurchase program is subject to reevaluation in the event of changes in market conditions. As of February 15, 2007, we had repurchased or committed to repurchase a total of 10.2 million shares with an aggregate cost of $492 million. The repurchase program is not subject to an expiration date.

Equity Compensation Plan Information. The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2006.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	6,211,750	$24.24	5,177,323
Equity compensation plans not approved by security holders	—	—	—
Total	6,211,750	$24.24	5,177,323

Stock Performance Graph. This graph shows our cumulative total shareholder return over the five-year period from December 31, 2001, to December 31, 2006. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index and our peer group of companies. At December 31, 2006 (after certain industry consolidation during 2006), our peer group of companies consisted of Anadarko Petroleum Corp., Apache Corp., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., Forest Oil Corp., Houston Exploration Company, Murphy Oil Corp., Newfield Exploration Company, Pioneer Natural Resources Company, Pogo Producing Company, Stone Energy Corp., and XTO Energy Inc. The comparison assumes $100 was invested on December 31, 2001, in our common stock, in the S&P 500 Index and in our peer group and assumes that all of the dividends were reinvested.



	12/01	12/02	12/03	12/04	12/05	12/06
Noble Energy, Inc.	100.00	106.90	127.09	177.09	232.41	284.65
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03
Peer Group	100.00	104.62	135.35	176.81	272.75	265.30

Item 6. Selected Financial Data

	Year ended December 31,				
	2006	2005 [(1)]	2004	2003	2002
	(in thousands, except share amounts)				
Revenues and Income:					
Revenues	$2,940,082	$2,186,723	$1,351,051	$1,008,226	$ 703,068
Income from continuing operations	678,428	645,720	313,850	89,892	8,095
Net income	678,428	645,720	328,710	77,992	17,652
Per Share Data:					
Basic earnings per share—					
Income from continuing operations	$ 3.86	$ 4.20	$ 2.69	$ 0.79	$ 0.07
Net income	3.86	4.20	2.82	0.68	0.15
Cash dividends	0.275	0.15	0.10	0.085	0.08
Year-end stock price	49.07	40.30	30.83	22.22	18.78
Basic weighted average shares outstanding	175,707	153,773	116,550	113,928	114,392
Financial Position:					
Property, plant, and equipment, net	$7,170,757	$6,198,916	$2,180,715	$2,046,909	$2,128,140
Goodwill	781,290	862,868	—	—	—
Total assets	9,588,625	8,878,033	3,435,784	2,820,800	2,730,016
Long-term obligations—					
Long-term debt	1,800,810	2,030,533	880,256	776,021	977,116
Deferred income taxes	1,758,452	1,201,191	180,415	161,912	201,939
Asset retirement obligations	127,689	278,540	175,415	101,804	—
Derivative instruments	328,875	757,509	9,678	7,400	337
Other deferred credits and noncurrent liabilities	274,720	279,971	69,479	72,776	69,483
Shareholders' equity	4,113,817	3,090,144	1,459,988	1,073,573	1,009,386
Continuing Operations Information:					
Natural gas production (Mcfpd)	622,927	508,195	366,965	336,611	341,008
Average realized price ($/Mcf) [(2)]	$ 5.55	$ 5.78	$ 4.76	$ 4.19	$ 2.89
Crude oil production (Bopd)	74,915	56,958	44,481	35,101	28,232
Average realized price ($/Bbl) [(2)]	$ 54.47	$ 45.35	$ 34.48	$ 27.67	$ 24.22
Equity investee production (Bopd)	8,032	3,240	894	913	882
Average realized price ($/Bbl)	$ 45.83	$ 43.43	$ 32.01	$ 25.47	$ 17.82

(1) Includes effect of Patina Merger. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures for additional information.

(2) Prices include effects of oil and gas hedging activities. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

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

We are an independent energy company engaged in the exploration, development, production and marketing of crude oil and natural gas. We have exploration, development and production operations domestically and internationally. We operate throughout major basins in the U.S. including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan Basin in New Mexico, the Gulf Coast and the Gulf of Mexico. We also conduct business internationally, in West Africa (Equatorial Guinea and Cameroon), the Mediterranean Sea, Ecuador, the North Sea, China, Argentina and Suriname.

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 balanced between domestic and international projects. Our Patina merger, purchase of U.S. Exploration and recent sale of Gulf of Mexico shelf properties have allowed us to achieve a strategic objective of enhancing our U.S. asset portfolio. The result is a company with assets and capabilities that include growing U.S. basins coupled with a significant portfolio of international properties. In 2006 our crude oil and natural gas sales volumes were 29% higher than 2005 and 75% higher than 2004. Our reserve base is balanced between domestic and international sources at 55% domestic and 45% international. We are now a larger, more diversified company with greater opportunities for both domestic and international growth.

2006 was a strong year for us, both financially and operationally. Significant financial information included the following:

- net income of $678 million, a 5% increase over 2005 net income, and a 100% increase over 2004 net income;
- pretax gain of $211 million on the sale of the Gulf of Mexico shelf properties;
- recognition of a non-cash pretax charge of $399 million related to previously forecasted hedge production that was no longer probable of occurring due to the sale of Gulf of Mexico shelf properties (See Item 8—Financial Statements and Supplementary Information—Note 12—Derivative Instruments and Hedging Activities);
- diluted earnings per share of $3.79, an 8% decrease from 2005 and a 37% increase over 2004;
- cash flow provided by operating activities of $1.730 billion, a 40% increase over 2005 and a 144% increase over 2004;
- cash flow used in investing activities of $1.098 billion, a 42% decrease from 2005 and an 87% increase over 2004;
- cash flow used in financing activities of $589 million, as compared with $583 million provided by financing activities in 2004 and $3 million used in financing activities in 2004; and
- completion of 80% of a newly implemented $500 million common stock repurchase program.

Significant operational highlights included the following:

- purchase of U.S. Exploration;
- sale of Gulf of Mexico shelf properties;
- commencement of production from the Ticonderoga deepwater Gulf of Mexico development (Green Canyon Block 768) on February 16, 2006;

- commencement of production from the Lorien deepwater Gulf of Mexico development (Green Canyon Block 199) on April 27, 2006;
- Gulf of Mexico deepwater discoveries at Redrock prospect (Mississippi Canyon Block 204) and at Raton prospect (Mississippi Canyon Block 248);
- Piceance Basin production growth of greater than 400% year-over-year from successful drilling and completion of 36 wells during 2006;
- continued expansion of Niobrara Trend in eastern Colorado, Kansas and Nebraska with the completion of 20 commitment wells with Teton Energy Corporation earning a 75% working interest in approximately 184,000 acres;
- acquisition of a 50% participating interest in the PH-77 license, offshore the Republic of Cameroon;
- full year of production from the Phase 2B liquids expansion project in Equatorial Guinea;
- overall daily sales volumes that were 29% higher than 2005 and 75% higher than 2004;
- average realized crude oil prices that were 20% higher than 2005 and 58% higher than 2004; and
- average realized natural gas prices that were 4% lower than 2005 and 17% higher than 2004.

Portfolio Enhancements—During 2006, we continued to enhance our portfolio with significant purchases and divestitures of assets.

On July 14, 2006, we sold substantially all of our Gulf of Mexico shelf properties except for the Main Pass area, which continues to undergo repair work after suffering significant hurricane damage in 2004 and 2005. The sale of these non-core assets allows us to focus future investments and growth in areas with higher potential. Pretax cash proceeds from the sale totaled $506 million including proceeds received from parties who exercised preferential rights to purchase certain properties. The sale resulted in lower sales volumes of approximately 10,700 Boepd in 2006. As of March 1, 2006, the effective date of the sale, proved reserves for the assets sold totaled approximately 7 MMBbls of crude oil and 120 Bcf of natural gas. A pretax gain of $211 million from the sale is included in our results of operations. The asset disposition did not qualify for accounting as discontinued operations, in accordance with EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations". This is due to the migration of our investment and operations to the Gulf Coast onshore and deepwater Gulf of Mexico areas.

On March 29, 2006, we purchased the common stock of U.S. Exploration, a privately held corporation located in Billings, Montana, for $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located in Colorado's Wattenberg field. This acquisition significantly expands our operations in one of our core areas. Proved reserves of U.S. Exploration are estimated to be approximately 248 Bcfe, of which 41% are proved developed and 55% are natural gas. Our consolidated operating and cash flow information includes financial results of U.S. Exploration after March 29, 2006.

Common Stock Repurchase Program—On May 16, 2006, we announced that our Board of Directors had authorized the repurchase of up to $500 million of common stock. We may buy shares from time to time on the open market or in negotiated purchases and expect to fund the repurchases primarily from cash flows from operations. The timing and amounts of any repurchases will be at management's discretion and in accordance with securities laws and other legal requirements. The repurchase program is subject to reevaluation in the event of changes in market conditions. During 2006, we repurchased 8.4 million shares of our common stock at an aggregate cost of $399 million.

Adoption of SFAS 123(R)—We adopted Statement of Financial Accounting Standards ("SFAS") No. 123(R), "Share-Based Payment," ("SFAS 123(R)") as of January 1, 2006. As a result, we recognized compensation expense of $12 million related to stock-based awards during 2006. This expense relates to stock-based awards made in 2006 and prior years that vest in 2006 and thereafter. As a result of this change in accounting method, our net income was reduced by $4 million, or $0.02 per diluted share, for 2006. In addition, tax benefits of $26 million related to option exercises were included in cash flows from financing activities rather than cash flows from operating activities. For 2005, tax benefits of $15 million were included in cash flows from operating activities.

Domestic Operations—Domestic operations benefited from a 45% increase in production and higher realized prices for crude oil in 2006. During 2006, our North America division continued to grow production despite the sale of Gulf of Mexico shelf properties. Onshore, significant activity continued in the Rocky Mountain and onshore Gulf coast areas. We completed significant deepwater developments in the Gulf of Mexico that added substantial new production during 2006. Significant operational highlights included the following:

- overall daily sales volumes that were 45% higher than 2005 and 96% higher than 2004;
- overall onshore daily sales volumes that were 46% higher than 2005 and 246% higher than 2004;
- deepwater daily sales volumes that were 535% higher than 2005 and 263% higher than 2004;
- average realized crude oil prices that were 9% higher than 2005 and 55% higher than 2004;
- average realized natural gas prices that were 11% lower than 2005 and 10% higher than 2004;
- exploration discoveries at Redrock and Raton in the Gulf of Mexico and completion of Raton appraisal well;
- first production from the Ticonderoga deepwater Gulf of Mexico development first quarter 2006;
- first production from the Lorien deepwater Gulf of Mexico development second quarter 2006; and
- successful divestiture of Gulf of Mexico shelf assets.

International Operations—International operations benefited from higher realized prices for crude oil and natural gas in 2006, and a 7% overall increase in production. During 2006, we participated in the drilling of six development wells in the North Sea, two development wells offshore in China and 58 development wells in Argentina. Significant operational highlights included the following:

- overall daily sales volumes that were 7% higher than 2005 and 47% higher than 2004;
- overall higher realized crude oil and natural gas prices;
- full year of production from the Phase 2B liquids expansion project which included increasing processing capacity, storage and offloading facilities at the existing LPG plant in Equatorial Guinea;
- increased natural gas infrastructure in Israel; and
- significant progress at the Dumbarton development in the North Sea, which commenced production in January 2007.

Recent Developments in Equatorial Guinea—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.

2007 OUTLOOK

We expect crude oil and natural gas production from continuing operations to increase in 2007 compared to 2006. Factors which may impact our expected year-over-year increase in production include:

- production contributions from the sale of natural gas from the Alba field in Equatorial Guinea to an LNG facility;
- the contribution of production from the Dumbarton North Sea development, which commenced on January 20, 2007;
- growing natural gas sales in Israel due to the planned conversion of additional power plants to use natural gas as fuel;

- growing production from the Piceance Basin, where we are continuing an active drilling program;
- a full year of production from the acquisition of U.S. Exploration, which closed on March 29, 2006;
- partially offset by loss of production from Gulf of Mexico shelf properties sold in July 2006 and natural production decline in certain fields.

Factors which may impact our expected production profile include:

- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project;
- infrastructure development in Israel;
- potential weather-related shut-ins in the Gulf of Mexico and Gulf Coast areas;
- potential weather-related volume curtailments in the Northern region; and
- capital expenditures, as discussed below, which are expected to result in near-term production.

2007 Budget—We have budgeted capital expenditures of $1.42 billion for 2007. Approximately 26% of the 2007 capital budget has been allocated to exploration opportunities and 74% has been allocated to production, development and other projects. Domestic spending is budgeted for $1.09 billion (77% of the 2007 capital budget), international expenditures are budgeted for $300 million (21%) and corporate expenditures are budgeted for $28 million (2%). The 2007 budget does not include the impact of possible asset purchases. We expect that the 2007 capital budget will be funded primarily from cash flows from operations. We will evaluate the level of capital spending throughout the year based upon drilling results, commodity prices, cash flows from operations and property acquisitions.

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 May 2005 and the acquisition of U.S. Exploration in March 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 revenues. For estimated proved reserves, the future net revenues 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 revenues 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 expense, which results in a decrease in future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher future estimates of crude oil and natural gas prices, could increase the likelihood of an impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. An 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.

Certain data necessary to complete the final purchase price allocation for U.S. Exploration is not yet available, and includes, but is not limited to, final valuation of pre-acquisition contingencies, final tax returns that provide the underlying tax bases of assets and liabilities, and final appraisals of assets acquired and liabilities assumed. We expect to complete the valuation of assets and liabilities (including deferred taxes) for the purpose of allocation of the total purchase price amount to assets acquired and liabilities assumed during the twelve-month period following the acquisition date. Any future change in the value of net assets up until the one year period has expired will be offset by a corresponding increase or decrease in goodwill. Any change in deferred tax assets and liabilities as of the acquisition date based on information that becomes available later will be recorded as an increase or decrease in goodwill.

Goodwill—As of December 31, 2006, the consolidated balance sheet included $781 million of goodwill, all of which has been assigned to the domestic 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, 2006. 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 domestic 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 market multiples of EBITDA (earnings before interest, taxes, and depreciation, depletion and amortization ("DD&A")) and EBIT (earnings before interest and taxes).

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 2006, 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 domestic reporting unit goodwill to the carrying amount of our Gulf of Mexico shelf properties sold in July 2006. 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.

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. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by our engineers. 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 capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take 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, 2006, the balance of property, plant and equipment included $80 million of suspended exploratory well costs, $22 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 an 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 a property impairment. We recorded approximately $9 million of impairments in 2006, primarily related to downward reserve revisions on domestic properties.

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 2006, we recorded impairments of significant unproved oil and gas properties totaling approximately $1 million.

Asset Retirement Obligation—Our asset retirement obligations ("ARO") consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. SFAS No. 143, "Accounting for Asset Retirement Obligations," requires that the 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. At December 31, 2006, the consolidated balance sheet included a liability for ARO of $196 million, including $65 million resulting from hurricane damage. 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 a decrease in the involuntary conversion gain, which will result in a decrease in net income. An increase in estimated costs of salvage, if not covered by insurance, will 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.

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 and the hedging 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. See Item 8—Financial Statements and Supplementary Data—Note 11—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 $31 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.

Retirement 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 obligation 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 obligation 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 December 31, 2006, cumulative asset gains of approximately $2 million remained to be recognized in the calculation of the market-related value of assets.

We utilize the services of an outside actuarial firm to assist in the calculations of the projected benefit obligation and related costs. The actuaries use historical data and forecasts to determine assumptions regarding future events. 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 obligation. This includes considering the returns being earned by the plan assets and the rates of return expected to be available for reinvestment. It is assumed 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 the plan's asset allocation. A 1% decrease in the expected return on plan assets assumption would have increased 2006 net periodic benefit cost by approximately $1 million. The expected return assumption used for 2006 was 8.25%.

In accordance with SFAS No. 87, "Employers' Accounting for Pensions," 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 select a discount rate. In order to determine an appropriate December 31, 2006 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 2006 net periodic benefit cost by $4 million and decreased the benefit obligation for the combined plans by $25 million at December 31, 2006. A 1% decrease in the discount rate assumption would have increased 2006 net periodic benefit cost by $5 million and increased the benefit obligation for the combined plans by $31 million at December 31, 2006. The assumed discount rate was 5.5% for January through April 2006. The net periodic pension cost was remeasured at May 1, 2006 using a discount rate of 6.25%, due to changes in plan provisions. The assumed discount rate at December 31, 2006 was 5.75%.

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. The effect of adoption included a $25 million decrease in other assets, a $28 million increase in accrued benefit costs, a $20 million decrease in deferred tax liabilities and a $33 million (net of tax of $20 million) decrease in shareholders' equity (effected by increasing AOCL). See Item 8—Financial Statements and Supplementary Data—Note 11—Employee Benefit Plans.

Recently Issued Pronouncements—See Item 8—Financial Statements and Supplementary Data—Note 17—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 for interest payments on debt. 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 properties.

We have reduced our ratio of debt-to-book capital (defined as total debt divided by the sum of total debt plus equity) from 40% at December 31, 2005, to 30% at December 31, 2006. Significant changes in our financial position causing a change in the ratio of debt-to-book capital include:

- a $230 million decrease in total debt from the balance at December 31, 2005;
- a $678 million increase in retained earnings from current year net income;
- a $63 million increase in capital in excess of par value from the exercise of stock options; and

- a $643 million increase in shareholders' equity (effected by decreasing AOCL) primarily related to a decrease in deferred hedge losses.

Cash Flows

Operating Activities—Cash flows from operating activities totaled $1.730 billion in 2006, a $490 million increase over 2005. Factors contributing to the increase included:

- a $536 million increase in oil and gas sales due to higher sales volumes;
- a $250 million increase in oil and gas sales due to higher realized crude oil prices, offset by a $51 million decrease due to lower realized natural gas prices;
- offset by a $141 million increase in total production costs (lease operating costs, production and ad valorem taxes and transportation expense), a $64 million increase in general and administrative expense, and a $30 million increase in interest expense.

Cash flows from operating activities totaled $1.240 billion in 2005, a $532 million increase over 2004. Factors contributing to the increase included:

- a $395 million increase in oil and gas sales due to higher sales volumes;
- a $406 million increase in oil and gas sales due to higher realized crude oil and natural gas prices;
- offset by a $112 million increase in total production costs (lease operating costs, production and ad valorem taxes and transportation expense), a $38 million increase in general and administrative expense, and a $35 million increase in interest expense.

Cash flows from operating activities totaled $708 million in 2004, a $105 million increase over 2003. Factors contributing to the increase in cash flows from operating activities included:

- a $144 million increase in oil and gas sales due to higher sales volumes;
- a $183 million increase in oil and gas sales due to higher realized crude oil and natural gas prices;
- offset by a $74 million increase in total production costs (lease operating costs, production and ad valorem taxes and transportation expense) and a $7 million increase in general and administrative expense.

Investing Activities—Net cash used in investing activities totaled $1.098 billion in 2006, a $794 million decrease from 2005. Significant investing activities included:

- $412 million used for the purchase of U.S. Exploration;
- $1.357 billion used for capital expenditures;
- partially offset by $520 million net proceeds from asset sales; and $155 million distributions received from equity method investees.

Net cash used in investing activities totaled $1.892 billion in 2005, a $1.304 billion increase over 2004. Significant investing activities included:

- $1.1 billion used for the Patina Merger; and
- $786 million used for capital expenditures.

Net cash used in investing activities totaled $588 million in 2004. Significant investing activities included:

- $554 million used for capital expenditures; and
- $104 million investments in equity method investees;
- partially offset by $62 million net proceeds from asset sales.

Financing Activities—Net cash used in financing activities totaled $589 million in 2006. Significant financing activities included:

- $230 million net reduction in short-term and long-term borrowings;
- $49 million cash dividends paid on our common stock;
- $399 million paid for repurchases of our common stock;
- offset by $63 million proceeds from the exercise of stock options.

Net cash provided by financing activities totaled $583 million in 2005. Significant financing activities included:

- $539 million net increase in long-term borrowings;
- $24 million cash dividends paid on our common stock;
- offset by $68 million proceeds from the exercise of stock options.

Net cash used in financing activities totaled $3 million in 2004. Significant financing activities included:

- $54 million net reduction in long-term borrowings;
- $12 million cash dividends paid on our common stock;
- offset by $63 million proceeds from the exercise of stock options.

Acquisition and Capital Expenditures

Capital expenditure information (on an accrual basis) is as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Capital Expenditures			
Lease acquisition of unproved property	53,652	16,793	44,685
Exploration expenditures	203,035	161,515	100,847
Development expenditures	1,054,780	662,585	399,217
Corporate and other expenditures	35,069	21,478	22,639
Investments in equity method investees	580	27,639	61,498
Total capital expenditures	1,347,116	890,010	628,886

Values preliminarily allocated to proved and unproved crude oil and natural gas properties acquired in the acquisition of U.S. Exploration were $413 million and $131 million, respectively. Values allocated to proved and unproved crude oil and natural gas properties acquired in the Patina Merger were $2.642 billion and $1.068 billion, respectively.

Total capital expenditures during 2006 increased $457 million, or 51%, as compared with 2005. The increase was primarily due to development expenditures in the U.S. and North Sea. Total capital expenditures during 2005 increased $261 million, or 42%, as compared with 2004. Capital expenditures for 2005 included $275 million of post-merger exploration and development-related expenditures on Patina properties.

Insurance Recoveries

Hurricane Katrina in 2005 and Hurricane Ivan in 2004 caused substantial damage to our Main Pass assets. Since then we have committed significant resources to salvage and clean-up operations and restoration of production. As related to Hurricane Katrina, we have been notified by our insurance carrier that we should expect to recover no more than 50% of our total claim due to submission of total industry claims from Katrina damage in excess of a $1 billion ceiling limitation per event. However, we currently expect to recover sufficient insurance proceeds to cover the expected salvage and clean-up costs and have offset anticipated insurance proceeds against the accrued salvage and clean-up expense except for a $1.0 million deductible. As of December 31, 2006, we have incurred $79 million (cumulative) in costs related to Hurricane Katrina damage, $16.5 million of which has been approved and reimbursed by our insurance carriers. As of December 31, 2006, we had recorded probable insurance claims of $64 million, the estimated remaining recovery for losses sustained from Hurricane Katrina. Total costs for clean-up and redevelopment are currently estimated at approximately $183 million. We expect to complete clean-up work during 2007 and receive final reimbursements thereafter.

As of December 31, 2006, based upon work completed, we have incurred $203 million (cumulative) in costs related to Hurricane Ivan damage. Our insurance carriers have approved and reimbursed $176 million of these costs, with the balance pending subsequent review and approval. We expect to fully recover through insurance proceeds all salvage and clean-up expenses and a portion of our redevelopment capital. Future redevelopment expenditures will be capitalized as development costs, net of any remaining insurance proceeds.

We carry up to $259 million property damage coverage per loss event. During first quarter 2006, our insurance carrier determined that its aggregation limit would be reduced from $1 billion to $500 million effective June 1, 2006. This insurance company modification, in response to large claims from losses caused by Hurricanes Katrina and Rita, increases the risk that we could recover less than our stated limits on any insured catastrophic loss event should the total aggregate losses realized by our carrier exceed its $500 million aggregation limit applicable to any single loss event. Although the insurance industry has reduced underwriting capacity for windstorm exposure in the Gulf of Mexico, we were able to secure $100 million additional insurance coverage applicable to specified deepwater properties, in the form of a package policy that covers property damage on an excess of loss limits basis, in addition to coverage for primary/contingent business interruption due solely to named windstorm loss events. The need for this package policy will be assessed annually and there is no assurance that we will elect to or be able to secure adequate insurance coverage for Gulf of Mexico windstorm exposure at policy expiration.

Financing Activities

Long-Term Debt—Our long-term debt totaled $1.801 billion (net of unamortized discount) at December 31, 2006. Maturities range from 2009 to 2097. Our principal source of liquidity is a $2.1 billion unsecured revolving credit facility (the "Credit Facility"). The Credit Facility, as amended in November 2006, (i) extends the maturity date of the Credit Facility to December 9, 2011, (ii) provides for Credit Facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (iii) makes available swingline loans up to an aggregate amount of $300 million and (iv) 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 amendment to the Credit Facility eliminated the financial covenant requiring a 4.0 to 1.0 ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense to interest expense. However, the Credit Facility continues to require that our total debt to capitalization ratio, 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, 2006, the total debt to capitalization ratio was 30%, calculated for this purpose as total debt divided by the sum of total debt plus equity, with increases or decreases thereto as provided by the Credit Facility.

The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes. At December 31, 2006, $1.155 billion in borrowings were outstanding under the Credit Facility. The weighted average interest rate applicable to borrowings under the Credit Facility at December 31, 2006 was 5.69%.

Short-Term Borrowings—Our credit agreement is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no short-term borrowings outstanding at December 31, 2006.

Debt Repayments—During 2006, we prepaid $105 million of term loans due January 2009. We also reduced the credit facility during 2006 with net payments of $125 million. See Item 8 — Financial Statements and Supplementary Data—Note 7 — Debt—Term Loans.

We made cash interest payments of $118 million, $93 million and $47 million during 2006, 2005 and 2004, respectively.

Dividends—Cash dividends totaled 27.5 cents per common share in 2006, 15 cents per common share in 2005 and 10 cents per common share in 2004. On January 23, 2007, the Board of Directors declared a quarterly cash dividend of 7.5 cents per common share, which was paid February 20, 2007 to shareholders of record on February 5, 2007. 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—We received $63 million, $68 million and $63 million from the exercise of stock options during 2006, 2005 and 2004, respectively. Proceeds received from the exercise of stock options fluctuate primarily based on the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued. Of the $63 million received from the exercise of stock options during 2006, $46 million resulted from the exercise of Patina options that had been exchanged for Noble Energy options in the Patina Merger. Of the $68 million received from the exercise of stock options during 2005, $44 million resulted from the exercise of Patina options that had been exchanged for Noble Energy options in the Patina Merger.

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, 2006, 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	2007	2008 and 2009	2010 and 2011	2012 and Beyond
			(in thousands)		
Contractual Obligations:					
Long-term debt (excludes interest) (Note 7) [1]	$1,805,000	$ -	$ -	$1,155,000	$650,000
Service contracts (Note 14)—					
Gulf of Mexico drilling rigs and services	484,212	124,080	167,202	130,980	61,950
West Africa drilling rigs and services	112,867	112,867	-	-	-
Northern region drilling rigs and services	135,481	75,988	53,017	6,476	-
Operating lease obligations (Note 14)—					
Office buildings and facilities	51,967	10,237	12,177	11,568	17,985
Oil and gas operations equipment	6,787	5,168	1,619	-	-
Purchase obligations (Note 14)	16,052	16,052	-	-	-
Other long-term liabilities [2]—					
Asset retirement obligations (Note 6) [3]	196,189	68,500	17,245	3,998	106,446
Derivative instruments (Note 12)	545,396	219,383	325,071	942	-
Total contractual obligations	$3,353,951	$632,275	$576,331	$1,308,964	$836,381

(1) We anticipate cash payments for interest of $111 million for 2007, $221 million for 2008 and 2009, $221 million for 2010 and 2011 and $1.035 billion for the remaining years for a total of $1.588 billion.

(2) The above amounts do not include our pension benefit obligation. See Item 8—Financial Statements and Supplementary Data—Note 11—Employee Benefit Plans.

(3) Asset retirement obligations are discounted.

We accrued approximately $11 million as of December 31, 2006, for an insurance contingency because of our membership in Oil Insurance Limited (OIL). OIL is an insurance pool which insures specific property, pollution liability and other catastrophic risks. As part of our membership, we are contractually committed to pay termination fees if we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, the potential termination fee is calculated annually based on policyholders' past losses and the liability reflecting this potential charge has been accrued as required.

In January 2007, we entered into a five-year throughput and deficiency agreement with a financial commitment of $95 million. The transporting pipeline, the construction of which is subject to regulatory approval, is expected to be completed and operational in 2009.

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 $14 million at December 31, 2006.

Other

Contributions to Pension and Other Postretirement Benefit Plans—We made contributions to pension and other postretirement benefit plans of $36 million during 2006, $14 million during 2005, and $5 million during 2004. The actual returns on plan assets were $13 million in 2006, $6 million in 2005, and $8 million in 2004. 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 the contribution made to the pension plan in 2006, there are no required contributions expected during 2007. We expect to make contributions of $2 million to the restoration and medical and life plans in 2007.

Income Taxes—We made cash payments for income taxes, net of refunds, of $115 million during 2006, $122 million during 2005 and $112 million during 2004.

Contingencies—During 2006, 2005, and 2004 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 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 revenues, driven primarily by a full year of Patina operations and nine months of U.S. Exploration operations;
- 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.

Net income for 2005 was $646 million, a 96% increase over 2004 net income of $329 million. Factors contributing to the increase in net income from 2004 to 2005 included:

- an $836 million, or 62%, increase in revenues, driven primarily by the addition of Patina properties in May 2005;
- offset by a $65 million increase in operating expense, an $82 million increase in DD&A, and a $61 million increase in exploration expense.

Natural Gas Information

Natural gas sales increased 18% in 2006 compared to 2005 due to a 23% increase in daily natural gas production offset by a 4% decrease in average realized natural gas prices. Higher sales volumes had a positive effect of $239 million on natural gas sales. Lower realized sales prices had a negative effect of $51 million on natural gas sales. Natural gas sales increased 70% in 2005 compared to 2004 due to a 38% increase in daily natural gas production and a 21% increase in average realized natural gas prices. Of the $420 million increase in natural gas sales, $240 million of the increase was due to higher sales volumes and $180 million was due to higher realized sales prices. Natural gas sales are net of the effects of the settlement of derivative contracts that are accounted for as cash flow hedges. See Item 8—Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Natural gas sales	$1,211,782	$1,023,644	$603,571

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

	Year ended December 31,					
	2006		2005		2004	
	Mcfpd	$/Mcf	Mcfpd	$/Mcf	Mcfpd	$/Mcf
United States [(1)]	451,712	$6.61	343,953	$7.43	240,647	$6.03
West Africa [(2)]	45,422	0.37	65,581	0.25	45,755	0.25
North Sea	8,130	8.00	9,299	5.93	11,286	4.73
Israel	92,894	2.72	66,377	2.68	48,015	2.78
Ecuador [(3)]	24,475	—	22,795	—	20,875	—
Other International	294	0.96	190	1.10	387	0.75
Total	622,927	$5.55	508,195	$5.78	366,965	$4.76

(1) Reflects reductions of $0.25 per Mcf in 2006, $0.77 per Mcf in 2005, and $0.08 per Mcf in 2004 from hedging activities.

(2) Natural gas in Equatorial Guinea is under contract for $0.25 per MMBtu through 2026 to a methanol plant and year-to-year to an LPG plant. Sales volumes declined in 2006 due to methanol plant turnaround followed by compressor maintenance and repairs. Each of these plants is owned by an affiliated entity 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. For 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 of $72 million, $74 million, and $59 million are included in total revenues for 2006, 2005 and 2004, respectively.

Factors contributing to the change in natural gas sales volumes in 2006 included:

- additional domestic production from Patina properties;
- additional domestic production from U.S. Exploration properties;
- increases in deepwater Gulf of Mexico production at Swordfish, Ticonderoga and Lorien;

- increased demand from Israel Electric Corporation Limited, full year of sales to Bazan Oil Refinery and commencement of natural gas sales to the Reading power plant in Tel Aviv, Israel;
- offset by the turnaround of the AMPCO methanol plant in Equatorial Guinea, which lasted 57 days, followed by reduced production levels caused by 35 days of compressor repairs.

Factors contributing to the change in natural gas sales volumes in 2005 included:

- additional domestic production from newly-acquired Patina properties;
- increase in Phase 2A (Alba field expansion project) production and start-up of Phase 2B (liquids expansion project) in Equatorial Guinea;
- higher production in Israel;
- higher production in Ecuador;
- offset by loss of production due to Gulf of Mexico hurricanes, and natural field decline in the Gulf of Mexico and North Sea.

Crude Oil Information

Crude oil sales increased 58% during 2006, compared to 2005, due to a 32% increase in consolidated daily crude oil production and a 20% increase in crude oil prices. Of the $547 million increase in crude oil sales, $297 million of the increase was due to higher sales volumes and $250 million was due to higher realized sales prices. Crude oil sales increased 68% during 2005, compared to 2004, due to a 28% increase in consolidated daily crude oil production and a 32% increase in crude oil prices. Of the $381 million increase in crude oil sales, $155 million of the increase was due to higher sales volumes and $226 million was due to higher realized sales prices. Crude oil sales are net of the effects of the settlement of derivative contracts that are accounted for as cash flow hedges. See Item 8—Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Crude oil sales	$1,489,459	$942,778	$561,404

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

	Year ended December 31,					
	2006		2005		2004	
	Bopd	$/Bbl	Bopd	$/Bbl	Bopd	$/Bbl
United States [(1)]	45,798	$50.68	25,941	$46.67	21,725	$32.64
West Africa [(2)]	17,860	62.51	17,786	42.51	9,190	38.16
North Sea [(3)]	3,717	67.43	5,380	52.68	6,718	38.90
Other International [(4)]	7,540	52.05	7,851	42.37	6,848	31.06
Total Consolidated Operations	74,915	54.47	56,958	45.35	44,481	34.48
Equity Investees [(5)]	8,032	45.83	3,240	43.43	894	32.01
Total	82,947	$53.64	60,198	$45.25	45,375	$34.44

(1) Reflects reductions of $11.41 per Bbl in 2006, $8.03 per Bbl in 2005, and $3.05 per Bbl in 2004 from hedging activities.

(2) Production averaged 17,326 Bopd in 2006. The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings. Average realized sales prices reflect reductions of $9.93 per Bbl in 2005 from hedging activities.

(3) Production averaged 3,988 Bopd in 2006. The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.

(4) Other international includes China and Argentina. Production averaged 7,491 Bopd in 2006. The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings

(5) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 6,294 Bopd, 2,328 Bopd, and 706 Bopd for 2006, 2005, and 2004, respectively.

Factors contributing to the change in crude oil sales volumes in 2006 included:

- timing of tanker liftings in Equatorial Guinea;
- additional domestic production from Patina properties;
- additional domestic production from U.S. Exploration properties;
- increases in deepwater Gulf of Mexico production at Swordfish, Ticonderoga and Lorien;
- full quarters of production from the Phase 2B liquids expansion project in Equatorial Guinea; and
- natural field decline in the North Sea and timing of tanker liftings.

Factors attributing to the change in crude oil sales volumes in 2005 included:

- additional domestic production from newly-acquired Patina properties;
- increase in Phase 2A (Alba field expansion project) production and start-up of Phase 2B (liquids expansion project) in Equatorial Guinea;
- new production from the Swordfish development in the Gulf of Mexico;
- increase in production in China;
- offset by loss of production due to Gulf of Mexico hurricanes, and natural field decline in the North Sea.

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. During 2006, 2005 and 2004, we recognized a reduction of revenues of $232 million, $238 million, and $61 million related to cash flow hedges in oil and gas sales. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.

Income from Equity Method Investees

We own a 45% interest in AMPCO LLC, which owns and operates a methanol production facility and related facilities in Equatorial Guinea and a 28% interest in Alba Plant LLC, which owns and operates an LPG processing plant. 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,		
	2006	2005	2004
Net income (in thousands):			
AMPCO LLC and affiliates	$ 38,024	$ 56,896	$ 69,100
Alba Plant LLC	101,338	33,916	9,099
Distributions/Dividends (in thousands):			
AMPCO LLC	37,350	59,625	57,825
Alba Plant LLC	155,158	—	—
Sales volumes:			
Methanol (Kgal)	109,942	162,446	146,821
Condensate (Bopd)	1,738	912	188
LPG (Bpd)	6,294	2,328	706
Average realized prices:			
Methanol (per gallon)	$ 0.90	$ 0.77	$ 0.69
Condensate (per Bbl)	$ 66.60	$ 55.76	$ 37.25
LPG (per Bbl)	$ 40.10	$ 38.63	$ 30.62

Net income from AMPCO, LLC in 2006 has declined relative to last year due to a 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006. The turnaround was followed by 35 days of compressor repairs, which resulted in reduced methanol production levels. The increases in net income for Alba Plant LLC and in condensate and LPG sales volumes reflect the completion and ramp up to full production of the Phase 2B liquids expansion project at the Alba plant.

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, 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
Year Ended December 31, 2004						
Oil and gas operating costs [(1)]	$136,471	$ 85,013	$20,811	$ 8,803	$7,203	$14,641
Workover and repair expense	16,635	16,635	—	—	—	—
Lease operating expense	153,106	101,648	20,811	8,803	7,203	14,641
Production and ad valorem taxes	28,022	21,806	—	—	—	6,216
Transportation expense	19,808	8,631	—	10,480	—	697
Total production costs	$200,936	$132,085	$20,811	$19,283	$7,203	$21,554

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

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

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 on March 29, 2006. In addition, the current high commodity price environment has 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 assets facing named windstorm exposure. Oil and gas operating costs increased $67 million, or 49% from 2004 to 2005. The 2005 increase primarily reflects expenses associated with properties acquired in the Patina Merger.

Workover and repair expense increased $33 million during 2006 as compared with 2005 and decreased $3 million during 2005 as compared with 2004. Expense for 2006 includes workover expense of $6 million associated with Patina properties and $41 million associated with other North America properties. It also includes $30 million ($0.45 per BOE) of hurricane-related repair expense.

Production and ad valorem tax expense increased $30 million, or 38% during 2006 as compared with 2005 and increased $51 million, or almost tripled, during 2005 as compared with 2004. The 2006 increase reflects additional production from U.S. Exploration properties and a full year of Patina operations. Patina and U.S. Exploration properties have proportionately more production subject to such taxes. In addition, crude oil and natural gas revenues generally are taxed at higher rates as commodity prices rise. The 2005 increase primarily reflects increased production and higher realized commodity prices.

Selected expenses on a per BOE basis were as follows:

	Year ended December 31,		
	2006	2005	2004
Oil and gas operating costs [1]	$4.14	$3.94	$3.53
Workover and repair expense [2]	0.72	0.27	0.43
Lease operating expense	4.86	4.21	3.96
Production and ad valorem taxes	1.67	1.52	0.73
Transportation expense	0.44	0.33	0.51
Total production costs	$6.97	$6.06	$5.20

[1] Includes domestic business interruption insurance of $0.21 per BOE in 2006.

[2] Includes hurricane-related repair expense of $0.45 per BOE in 2006.

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 2004. 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, 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
Year Ended December 31, 2004						
Dry hole expense	$ 46,192	$ 34,236	$4,676	$ 6,789	$ 293	$ 198
Unproved lease amortization	19,280	18,705	—	50	525	—
Seismic	23,360	20,288	2,115	550	—	407
Staff expense	22,990	13,926	260	3,374	305	5,125
Other	5,179	4,737	163	402	—	(123)
Total exploration expense	$117,001	$ 91,892	$7,214	$11,165	$1,123	$ 5,607

[1] Other international includes Ecuador, China, Argentina and Suriname.

Exploration expense decreased $11 million, or 6% during 2006 as compared with 2005, and increased $61 million, or 52%, during 2005 as compared with 2004. In 2006, U.S. dry hole expense was $30 million less due to the reduction in the number of dry holes drilled. U.S. seismic expense increased $18 million due primarily to the expansion of our deepwater regional 3D seismic database. In addition, other international staff expense increased $8 million due to new venture activity. Exploration expense for 2006 included stock-based compensation expense of $1 million. The 2005 increase was due to higher dry hole expense in the U.S. where a total of 37 net wells were classified as dry holes and expensed during the year.

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

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
United States	$543,431	$311,153	$240,058
West Africa	23,620	27,121	13,925
North Sea	8,123	9,888	18,244
Israel	13,947	11,188	9,058
Other International, Corporate, and Other	33,487	31,194	26,818
Total DD&A expense	$622,608	$390,544	$308,103
Unit rate of DD&A per BOE	$ 9.54	$ 7.55	$ 7.97

Total DD&A expense has been increasing since 2004 primarily due to higher production volumes. 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, Gulf of Mexico deepwater production carries a unit rate which is higher than the company average. As deepwater production has increased from 3,627 Boepd, or 3% of 2005 total consolidated production volumes to 25,432 Boepd, or 14% of total consolidated production volumes in 2006, the unit rate has increased. During 2005, the unit rate decreased from 2004 due to an increase in low-cost production volumes in Equatorial Guinea and Israel.

DD&A expense includes abandoned assets cost of $1 million, $11 million, and $15 million during 2006, 2005 and 2004, respectively.

General and Administrative Expense

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

	Year ended December 31,		
	2006	2005	2004
General and administrative expense (in thousands)	$164,541	$100,125	$61,852
Unit rate per BOE	$ 2.52	$ 1.94	$ 1.60

G&A expense increased $64 million, or 64% during 2006 as compared with 2005 and $38 million, or 62%, during 2005 as compared with 2004. The 2006 increase was due to higher salaries and wages and the inclusion of a full year of G&A expense related to Patina operations. We are experiencing wage inflation due to the tight labor market which has resulted from the current high commodity price environment. The 2005 increase reflects additional costs incurred relating to the combining of our operations with those of Patina. G&A expense for 2006 includes stock-based compensation expense of $11 million (calculated under SFAS 123(R)). G&A expense for 2005 and 2004 includes stock-based compensation expense (calculated under APB 25) of $4 million and $1 million, respectively.

G&A includes actuarially-computed net periodic benefit expense related to pension and other postretirement benefit plans of $19 million, $11 million and $9 million during 2006, 2005 and 2004, respectively.

Interest Expense and Capitalized Interest

Interest expense and capitalized interest were as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Interest expense, net	$117,045	$87,541	$53,460
Capitalized interest	12,515	8,684	8,168

Interest expense, net of capitalized interest, has been increasing 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 in 2006 relates to long lead-time projects in the North Sea and deepwater Gulf of Mexico. The majority of the capitalized interest in 2005 and 2004 relates to long lead-time projects in the deepwater Gulf of Mexico and internationally, primarily Phase 2A in Equatorial Guinea.

(Gain) Loss on Derivative Instruments

(Gain) loss on derivative instruments includes the following:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Reclassified from AOCL	$398,517	$(20,000)	$ —
Mark-to-market (gain) loss on derivatives not accounted for as cash flow hedges	(15,652)	51,750	—
Ineffectiveness losses	9,502	930	272
Total	$392,367	$ 32,680	$272

See Item 8—Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Other

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 expenses are included in other expense, net in the consolidated statements of operations.

Operating data is as follows:

	Year ended December 31,		
	2006	2005	2004
Electricity sales (in thousands)	$ 71,603	$ 74,228	$ 58,627
Electricity generation (in thousands)	59,494	53,137	47,788
Operating income (in thousands)	12,109	21,091	10,839
Power production (MW)	865,983	799,160	720,300
Average power price ($/Kwh)	$ 0.083	$ 0.093	$ 0.081

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

Electricity generation expense includes $15 million, $11 million and $5 million net increases in the allowance for doubtful accounts in 2006, 2005, and 2004, respectively. 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—NEMI, a wholly-owned subsidiary, marketed approximately 43% of our domestic natural gas production in 2006, as well as certain third-party natural gas. NEMI sells natural gas directly to end-users, natural gas marketers, industrial users, interstate and intrastate pipelines, power generators and local distribution companies. NEMI also markets 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. NEMI's gross margin from GMP activities was as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
GMP proceeds	$27,876	$55,261	$49,250
GMP expenses	18,664	28,067	37,699
Gross margin	$ 9,212	$27,194	$11,551

NEMI employs 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 made by NEMI are on an index basis. However, purchasers in the markets in which NEMI sells often require fixed or NYMEX-related pricing. NEMI records gains and losses on derivative instruments using mark-to-market accounting. The net gain related to these contracts totaled $1 million during 2006 and $2 million during 2005. Gains (losses) were de minimis for 2004. 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. Increases or decreases in the market value of the deferred compensation liability, including the shares of our common stock held by the rabbi trust, are included as deferred compensation expense and included in other expense, net in the consolidated statements of operations. We recorded deferred compensation expense of $28 million in 2006 and $18 million from the date of the Patina Merger through December 31, 2005. At December 31, 2006, 35% of the market value of the assets in the rabbi trust related to our common stock.

Impairment of Operating Assets—We recorded impairments of $9 million in 2006, $5 million in 2005, and $10 million in 2004, primarily related to downward reserve revisions on domestic properties. 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,		
	2006	2005	2004
Income tax provision (in thousands)	$417,789	$322,940	$199,158
Effective rate	38%	33%	39%

Several factors resulted in an increase in our effective tax rate for 2006. The major factor was the allocation of $100 million of nondeductible goodwill to the sale of the Gulf of Mexico shelf properties. At December 31, 2005, we had recorded a deferred U.S. tax asset of $55 million for the future foreign tax credits associated with deferred foreign tax liabilities recorded by our foreign branch operations. The valuation allowance with respect to the deferred U.S. tax asset was $41 million at December 31, 2005. The tax asset was decreased to $53 million during 2006, and the valuation allowance was increased to $53 million due to changes in the forecast of limitations on the ability to claim foreign tax credits. There was also an increase in the UK tax rate during 2006. The UK Finance Act of 2006, enacted on July 19, increased the income tax rate on our UK operations retroactive to January 1, 2006 and increased our income tax provision by approximately $9 million in 2006. Partially offsetting these increases was a benefit from the realization of additional income from equity method investees which is a favorable permanent difference in calculating income tax expense.

The decrease in the effective rate for 2005 was primarily due to our ability to claim a foreign tax credit for the income taxes paid by foreign branch operations, as well as to a benefit realized on the repatriation of foreign earnings under the American Jobs Creation Act of 2004. See Item 8—Financial Statements and Supplementary Data—Note 8—Income Taxes.

Discontinued Operations

During 2004, we completed an asset divestiture program including five domestic property packages. The sales price for the five property packages totaled $130 million. The consolidated financial statements have been reclassified for all periods previously presented to reflect the operations of the properties being sold as discontinued operations.

Summarized results of discontinued operations were as follows:

	Year ended December 31,
	2004
	(in thousands)
Oil and gas sales and royalties	$12,575
Realized gain	14,996
Income before income taxes	22,862
Key Statistics:	
Daily production	
Liquids (Bbls)	225
Natural Gas (Mcf)	4,429
Average realized price	
Liquids ($/Bbl)	$ 33.96
Natural Gas ($/Mcf)	$ 6.03

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes—We are exposed to market risk in the normal course of business operations. Management believes that we are well positioned with our mix of crude oil and natural gas reserves to take advantage of future price increases that may occur. However, the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we have used derivative hedging instruments and may do so in the future as a means of managing our exposure to price changes. During the past three years we have entered into variable to fixed price swaps, costless collars, and variable to fixed price basis swaps related to our crude oil and natural gas production as follows:

	Year ended December 31,		
	2006	2005	2004
Natural Gas Collars			
NYMEX -			
Hedge MMBtupd	12,082	79,932	120,284
Floor price range	\$5.00 - \$5.25	\$5.00 - \$5.75	\$3.75 - \$5.00
Ceiling price range	\$8.00 - \$10.20	\$7.20 - \$9.50	\$5.16 - \$9.65
Percent of daily worldwide production	2%	16%	33%
Crude Oil Collars			
NYMEX -			
Hedge Bopd	2,787	15,519	15,005
Floor price range	\$29.00 - \$60.00	\$29.00 - \$32.00	\$24.00 - \$28.00
Ceiling price range	\$35.50 - \$73.00	\$37.25 - \$46.15	\$30.00 - \$38.65
Percent of daily worldwide production	3%	26%	33%
Brent -			
Hedge Bopd	—	5,000	1,260
Floor price range	—	\$32.50 - \$37.50	\$37.50 - \$37.50
Ceiling price range	—	\$49.50 - \$56.50	\$54.00 - \$54.00
Percent of daily worldwide production	—	8%	3%
Natural Gas Swaps			
NYMEX -			
Hedge MMBtupd	170,000	87,260	—
Average price per MMBtu	\$ 6.49	\$ 6.76	—
Percent of daily worldwide production	27%	17%	—
Crude Oil Swaps			
NYMEX -			
Hedge Bopd	16,600	—	—
Average price per Bbl	\$ 40.47	—	—
Percent of daily worldwide production	18%	—	—
Brent -			
Hedge Bopd	—	8,793	—
Average price per Bbl	—	\$ 39.62	—
Percent of daily worldwide production	—	15%	—
Basis Swaps [1]			
CIG vs. NYMEX			
Hedge MMBtupd	58,685	—	—
Average differential per MMBtu	\$ 1.49	—	—
ANR vs. NYMEX			
Hedge MMBtupd	11,726	—	—
Average differential per MMBtu	\$ 1.14	—	—

[1] Basis swaps have been combined with NYMEX natural gas fixed price swaps

At December 31, 2006, we had entered into future costless collar and fixed price swap transactions related to crude oil and natural gas production and basis swap transactions related to natural gas production. See Item 8. Financial Statements and Supplementary Data — Note 12—Derivative Instruments and Hedging Activities.

As of December 31, 2006, we had a net unrealized loss of $167.2 million (pre-tax) related to crude oil and natural gas derivative instruments entered into for hedging purposes. A net unrealized loss of $104.3 million, net of tax, is recorded in AOCL in the shareholders' equity section of our consolidated balance sheet. We will reclassify the loss to earnings as adjustments to revenue when future production occurs.

Derivative Instruments Held for Trading Purposes—NEMI, from time to time, employs various derivative instruments in connection with purchases and sales of production. While most of the purchases are made for an index-based price, customers often require prices that are either fixed or related to NYMEX. In order to establish a fixed margin and mitigate the risk of price volatility, NEMI may convert a fixed or NYMEX sale to an index-based sales price (such as purchasing a NYMEX futures contract at the Henry Hub with an adjoining basis swap at a physical location). Due to the size of such transactions and certain restraints imposed by contract and by our internal guidelines, we believe we had no material market risk exposure from these derivative instruments as of December 31, 2006. Unrealized gains and losses are reflected in earnings as incurred.

Interest Rate Risk

We are exposed to interest rate risk related to our variable and fixed interest rate debt. As of December 31, 2006, we had $1.805 billion of debt outstanding of which $650 million was fixed-rate debt. We believe that anticipated near term changes in interest rates will not have a material effect on the fair value of our fixed-rate debt and will not expose us to the risk of earnings or cash flow loss.

The remainder of our debt at December 31, 2006 was variable-rate debt and, therefore, exposes us to the risk of earnings or cash flow loss due to changes in market interest rates. At December 31, 2006, $1.155 billion of variable-rate debt was outstanding. A 10% change in the floating interest rates applicable to the December 31, 2006 balance would result in a change in annual interest expense of approximately $7 million.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2006, AOCL included $3 million, net of tax, related to a settled interest rate lock. This amount is being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014.

Foreign Currency Risk

We have not entered into foreign currency derivatives. The U.S. dollar is considered the functional currency for each of our international operations. Transactions that are completed in a foreign currency are remeasured into U.S. dollars and recorded in the financial statements at the prevailing foreign exchange rates. Transaction gains or losses were not material in any of the periods presented and we do not believe we are currently exposed to any material risk of loss on this basis. Such gains or losses are included in other expense, net in the consolidated statements of operations.

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

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

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

As of December 31, 2006, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control—Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2006, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 and is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, shareholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of the Alba Plant LLC (Alba) and the Atlantic Methanol Production Company, LLC (AMPCO), the investments in which, as disclosed in Note 13 of the consolidated financial statements, are accounted for by the equity method of accounting. The Company's investment in Alba as of December 31, 2006 was $146.1 million and the equity in earnings in Alba was $101.3 million for the year ended December 31, 2006. The Company's investment in AMPCO as of December 31, 2005 was $214.2 million and the equity in earnings of AMPCO was $54.9 million and $66.8 million for the years ended December 31, 2005 and 2004, respectively. The financial statements of Alba and AMPCO were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Alba and AMPCO, are based solely on the report of other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for stock-based compensation. As also discussed in Note 2 to the consolidated financial statements, effective December 31, 2006, the Company changed its method of accounting for defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
February 23, 2007

Report of Independent Registered Public Accounting Firm

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Noble Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, management's assessment that Noble Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by COSO. Also, in our opinion, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, shareholders' equity, other comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 23, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 23, 2007

Noble Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

(in thousands, except share amounts)

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 153,408	$ 110,321
Accounts receivable - trade, net	586,882	566,206
Probable insurance claims	101,233	142,311
Deferred income taxes	99,835	237,045
Other current assets	127,188	119,628
Total current assets	1,068,546	1,175,511
Plant, property and equipment		
Oil and gas properties (successful efforts method of accounting)	8,867,639	8,411,426
Other plant, property and equipment	79,646	69,869
	8,947,285	8,481,295
Accumulated depreciation, depletion and amortization	(1,776,528)	(2,282,379)
Total property, plant and equipment, net	7,170,757	6,198,916
Other noncurrent assets	568,032	640,738
Goodwill	781,290	862,868
Total Assets	$ 9,588,625	$ 8,878,033
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 518,609	$ 519,971
Derivative instruments	254,625	445,939
Income taxes	107,136	65,136
Asset retirement obligations	68,500	60,331
Other current liabilities	235,392	148,768
Total current liabilities	1,184,262	1,240,145
Deferred income taxes	1,758,452	1,201,191
Asset retirement obligations	127,689	278,540
Derivative instruments	328,875	757,509
Other noncurrent liabilities	274,720	279,971
Long-term debt	1,800,810	2,030,533
Total Liabilities	5,474,808	5,787,889
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock - par value $1.00; 4,000,000 shares authorized, none issued	—	—
Common stock - par value $3.33 1/3; 250,000,000 shares authorized; 188,808,087 and 184,893,510 shares issued, respectively	629,360	616,311
Capital in excess of par value	2,041,048	1,945,239
Deferred compensation	—	(5,288)
Accumulated other comprehensive loss	(140,509)	(783,499)
Treasury stock, at cost: 16,574,384 and 9,268,932 shares, respectively	(511,443)	(148,476)
Retained earnings	2,095,361	1,465,857
Total Shareholders' Equity	4,113,817	3,090,144
Total Liabilities and Shareholders' Equity	$ 9,588,625	$ 8,878,033

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries

Consolidated Statements of Operations

(in thousands, except per share amounts)

	Year ended December 31, 2006	2005	2004
Revenues			
Oil and gas sales	$2,701,241	$1,966,422	$1,164,975
Income from equity method investees	139,362	90,812	78,199
Other revenues	99,479	129,489	107,877
Total Revenues	2,940,082	2,186,723	1,351,051
Costs and Expenses			
Lease operating costs	317,087	217,860	153,106
Production and ad valorem taxes	108,979	78,703	28,022
Transportation costs	28,542	16,764	19,808
Exploration costs	167,924	178,426	117,001
Depreciation, depletion and amortization	622,608	390,544	308,103
General and administrative	164,541	100,125	61,852
Accretion of discount on asset retirement obligations	10,797	11,214	9,352
Interest, net of amount capitalized	117,045	87,541	53,460
Loss on derivative instruments	392,367	32,680	272
Gain on sale of assets	(219,577)	(4,201)	(13,296)
Other expense, net	133,552	108,407	100,363
Total Costs and Expenses	1,843,865	1,218,063	838,043
Income Before Taxes	1,096,217	968,660	513,008
Income Tax Provision	417,789	322,940	199,158
Income From Continuing Operations	678,428	645,720	313,850
Discontinued Operations, Net of Tax	—	—	14,860
Net Income	$ 678,428	$ 645,720	$ 328,710
Earnings Per Share			
Basic -			
Income from continuing operations	$ 3.86	$ 4.20	$ 2.69
Discontinued operations, net of tax	—	—	0.13
Net Income	$ 3.86	$ 4.20	$ 2.82
Diluted -			
Income from continuing operations	$ 3.79	$ 4.12	$ 2.65
Discontinued operations, net of tax	—	—	0.13
Net Income	$ 3.79	$ 4.12	$ 2.78
Weighted average number of shares outstanding - Basic	175,707	153,773	116,550
Weighted average number of shares outstanding - Diluted	179,044	156,759	118,452

The accompanying notes are an integral part of these financial statements

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

	Year ended December 31,		
	2006	2005	2004
Cash Flows from Operating Activities			
Net income	$ 678,428	$ 645,720	$ 328,710
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization - oil and gas production	622,608	390,544	308,103
Depreciation, depletion and amortization - electricity generation	16,319	16,476	19,550
Dry hole expense	70,325	98,015	46,192
Impairment of operating assets	8,525	5,368	9,885
Amortization of unproved leasehold costs	18,923	17,855	19,280
Stock-based compensation expense	11,816	3,467	869
Non-cash effect of discontinued operations	—	—	(14,996)
Gain on sale of assets	(219,577)	(4,201)	(13,296)
Deferred income taxes	194,261	183,770	20,205
Accretion of discount on asset retirement obligations	10,797	11,214	9,352
Income from equity method investees	(139,362)	(90,812)	(78,199)
Dividends received from equity method investees	37,350	59,625	57,825
Deferred compensation expense	28,189	17,918	—
Loss on derivative instruments	415,298	32,680	272
Other	37,400	(33,870)	(21,563)
Changes in operating assets and liabilities, net of acquisition:			
(Increase) in accounts receivable	(32,348)	(73,940)	(99,886)
(Increase) in other current assets	(4,954)	(28,254)	(10,159)
Decrease (increase) in probable insurance claims	139,590	(25,306)	(3,146)
(Decrease) increase in accounts payable	(11,151)	20,747	43,093
(Decrease) increase in other current liabilities	(152,131)	(7,138)	86,095
Net Cash Provided by Operating Activities	1,730,306	1,239,878	708,186
Cash Flows From Investing Activities			
Additions to property, plant and equipment	(1,357,039)	(785,610)	(553,643)
U.S. Exploration acquisition, net of cash acquired	(412,257)	—	—
Patina acquisition, net of cash acquired	—	(1,111,099)	—
Proceeds from sale of property, plant and equipment	519,567	13,179	62,455
Investments in equity method investees	(3,768)	(13,927)	(104,062)
Distributions from equity method investees	155,158	4,969	7,149
Net Cash Used in Investing Activities	(1,098,339)	(1,892,488)	(588,101)
Cash Flows From Financing Activities			
Exercise of stock options	62,613	67,657	62,591
Excess tax benefits from stock-based awards	26,106	—	—
Cash dividends paid	(48,924)	(23,655)	(11,645)
Purchase of treasury stock	(398,675)	—	—
Proceeds from credit facilities	480,000	3,335,333	375,000
Repayment of credit facilities	(605,000)	(2,140,333)	(619,753)
Proceeds from term loans	—	—	150,000
Repayment of term loans	(105,000)	(45,000)	—
Repayment of Patina debt	—	(610,865)	—
Issuance of long-term debt	—	—	197,688
Repayment of notes	—	—	(156,546)
Net Cash (Used in) Provided by Financing Activities	(588,880)	583,137	(2,665)
Increase (Decrease) in Cash and Cash Equivalents	43,087	(69,473)	117,420
Cash and Cash Equivalents at Beginning of Period	110,321	179,794	62,374
Cash and Cash Equivalents at End of Period	$ 153,408	$ 110,321	$ 179,794
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 105,769	$ 83,860	$ 38,468
Income taxes paid, net	115,398	121,687	112,250
Non-cash financing and investing activities:			
Issuance of common stock and options and liabilities assumed in Patina Merger	—	3,783,306	—

The accompanying notes are an integral part of these financial statements

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

	Common Stock	Capital in Excess of Par Value	Deferred Compensation — Restricted Stock	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2003	$404,960	$ 228,728	$ —	$ (10,886)	$ (75,956)	$ 526,727	$1,073,573
Net income	—	—	—	—	—	328,710	328,710
Exercise of stock options	11,910	50,681	—	—	—	—	62,591
Tax benefits related to exercise of stock options	—	9,791	—	—	—	—	9,791
Issuance of restricted stock, net	282	2,258	(2,540)	—	—	—	—
Amortization of restricted stock	—	—	869	—	—	—	869
Cash dividends ($.10 per share)	—	—	—	—	—	(11,645)	(11,645)
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	39,840	—	—	39,840
Unrealized change in fair value	—	—	—	(39,161)	—	—	(39,161)
Interest rate cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	348	—	—	348
Unrealized change in fair value	—	—	—	(2,417)	—	—	(2,417)
Net change in minimum pension liability and other	—	—	—	(2,511)	—	—	(2,511)
Comprehensive loss				(3,901)			
December 31, 2004	$417,152	$ 291,458	$(1,671)	$ (14,787)	$ (75,956)	$ 843,792	$1,459,988
Net income	$ —	$ —	$ —	$ —	$ —	$ 645,720	$ 645,720
Patina Merger	185,568	1,576,799	—	—	(73,203)	—	1,689,164
Exercise of stock options	13,013	54,644	—	—	—	—	67,657
Tax benefits related to exercise of stock options	—	15,407	—	—	—	—	15,407
Issuance of restricted stock, net	578	6,506	(7,084)	—	—	—	—
Amortization of restricted stock	—	—	3,467	—	—	—	3,467
Cash dividends ($0.15 per share)	—	—	—	—	—	(23,655)	(23,655)
Rabbi trust shares sold	—	90	—	—	683	—	773
Other	—	335	—	—	—	—	335
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	154,500	—	—	154,500
Unrealized amounts reclassified into earnings	—	—	—	33,638	—	—	33,638
Unrealized change in fair value	—	—	—	(945,033)	—	—	(945,033)
Interest rate cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	492	—	—	492
Net change in minimum pension liability and other	—	—	—	(12,309)	—	—	(12,309)
Comprehensive income loss				(768,712)			
December 31, 2005	$616,311	$1,945,239	$(5,288)	$(783,499)	$(148,476)	$1,465,857	$3,090,144
Net income	$ —	$ —	$ —	$ —	$ —	$ 678,428	$ 678,428
Adoption of SFAS 123(R), net of tax	—	(5,288)	5,288	—	—	—	—
Stock—based compensation expense	—	11,816	—	—	—	—	11,816
Exercise of stock options	12,829	49,784	—	—	—	—	62,613
Tax benefits related to exercise of stock options	—	26,106	—	—	—	—	26,106
Issuance of restricted stock, net	220	(220)	—	—	—	—	—
Cash dividends ($0.275 per share)	—	—	—	—	—	(48,924)	(48,924)
Purchases of treasury stock	—	—	—	—	(398,675)	—	(398,675)
Rabbi trust shares sold	—	13,611	—	—	35,708	—	49,319
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	145,035	—	—	145,035
Unrealized amounts reclassified into earnings	—	—	—	264,520	—	—	264,520
Unrealized change in fair value	—	—	—	249,974	—	—	249,974
Interest rate cash flow hedges:							
Realized amounts reclassified into earnings	—	—	—	637	—	—	637
Net change in minimum pension liability and other	—	—	—	16,225	—	—	16,225
Comprehensive income				676,391			
Adoption of SFAS 158, net of tax	—	—	—	(33,401)	—	—	(33,401)
December 31, 2006	$629,360	$2,041,048	$ —	$(140,509)	$(511,443)	$2,095,361	$4,113,817

The accompanying notes are an integral part of these financial statements

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

	Year ended December 31,		
	2006	2005	2004
Net income	$ 678,428	$ 645,720	$328,710
Other comprehensive income (loss) items			
Oil and gas cash flow hedges:			
Realized amounts reclassified into earnings	232,428	237,692	61,292
Less tax provision	(87,393)	(83,192)	(21,452)
Unrealized amounts reclassified into earnings	423,910	51,750	—
Less tax provision	(159,390)	(18,112)	—
Unrealized change in fair value	351,637	(1,453,897)	(60,248)
Less tax provision	(101,663)	508,864	21,087
Interest rate cash flow hedges:			
Realized amounts reclassified into earnings	758	757	535
Less tax provision	(121)	(265)	(187)
Unrealized change in fair value	—	—	(3,718)
Less tax provision	—	—	1,301
Net change in minimum pension liability and other	25,002	(18,937)	(3,863)
Less tax provision	(8,777)	6,628	1,352
Other comprehensive income (loss)	676,391	(768,712)	(3,901)
Comprehensive income (loss)	$1,354,819	$ (122,992)	$324,809

The accompanying notes are an integral part of these financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in tables, unless otherwise indicated, are in thousands, except per share amounts)

Note 1—Nature of Operations

Noble Energy, Inc. ("Noble Energy", "we" or "us") is an independent energy company engaged in the exploration, development, production and marketing of crude oil and natural gas. We have exploration, exploitation and production operations domestically and internationally. We operate throughout major basins in the U.S. including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan Basin in New Mexico, the Gulf Coast and the Gulf of Mexico. In addition, we conduct business internationally in West Africa (Equatorial Guinea and Cameroon), the Mediterranean Sea, Ecuador, the North Sea, China, Argentina, and Suriname.

Note 2—Summary of Significant Accounting Policies

Basis of Presentation and Consolidation—Accounting policies used by Noble Energy and its subsidiaries conform to accounting principles generally accepted in the United States. Significant policies are discussed below. Our consolidated accounts include those of Noble Energy and its wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets plus loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. All significant intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

Estimates of crude oil and natural gas reserves are the most significant of our estimates. All of the reserve data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Engineers in our Houston and Denver offices perform 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 Senior Vice President with responsibility for corporate reserves. See Supplemental Oil and Gas Information.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment and goodwill; asset retirement obligations; valuation allowances for receivables and deferred income tax assets; valuation of derivative instruments; and assets and obligations related to employee benefits. Actual results could differ significantly from those estimates.

Common Stock Split—On August 17, 2005, our Board of Directors approved a two-for-one split of Noble Energy common stock that was effected in the form of a stock dividend. The stock dividend was distributed on September 14, 2005 to shareholders of record as of August 31, 2005. All share and per share data except par value have been adjusted to reflect the effect of the stock split for all periods presented.

Foreign Currency—The U.S. dollar is considered the functional currency for each of our international operations. Transactions that are completed in a foreign currency are remeasured into U.S. dollars and recorded in the financial statements at prevailing foreign exchange rates. Transaction gains or losses were not material in any of the periods presented and are included in other expense, net on the statements of operations.

Allowance for Doubtful Accounts—We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated.

Changes in the allowance for doubtful accounts are as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Balance at beginning of period	$18,644	$13,093	$ 6,255
Charged to expense	19,404	14,688	6,838
Collections of amounts previously charged to expense	(2,607)	(2,700)	—
Deductions	(906)	(6,437)	—
Balance at end of period	$34,535	$18,644	$13,093

Increases in the allowance of $15 million, $11 million and $5 million for 2006, 2005 and 2004, respectively, were made to cover potentially uncollectible balances related to Ecuador power operations and are included in electricity generation expense. 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. The allowance was increased by $2 million, $1 million and $1 million in 2006, 2005 and 2004, respectively, to record various provisions related to our domestic business. In addition, in 2005 the allowance was decreased due to the final write-off of certain allowances recorded in prior years ($6 million).

Materials and Supplies Inventories—Materials and supplies inventories, consisting principally of tubular goods and production equipment, are stated at the lower of cost or market, with cost being determined by the first-in, first-out method.

Property, Plant and Equipment—

Successful Efforts Method—We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by our engineers. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation, depletion and amortization ("DD&A") are eliminated from the accounts and the resulting gain or loss is recognized. Repairs and maintenance are expensed as incurred.

Proved Property Impairment—In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or sustained decrease in commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices and operating expenses, timing of future production, future capital expenditures and a risk-adjusted discount rate. We recorded impairments of approximately $9 million in 2006, $5 million in 2005 and $10 million in 2004, primarily related to downward reserve revisions on domestic properties.

Unproved Property Impairment—We also periodically assess individually significant unproved properties for impairment of value and recognize a loss at the time of impairment by providing an impairment allowance. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil and natural gas reserves, future commodity prices and future costs to extract the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. Other individually insignificant unproved properties are amortized on a composite method based on our experience of successful drilling and average holding period. During 2006, 2005, and 2004, we recorded impairments of individually significant unproved properties of approximately \$1 million, \$3 million, and \$4 million, respectively, in exploration expense.

Properties Acquired in Business Combinations—In determining the fair values of proved and unproved properties acquired in business combinations, we prepare estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by additional risk-weighting factors.

Exploration Costs—Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. Management assesses the status of suspended exploratory well costs on a quarterly basis. See Note 5—Capitalized Exploratory Well Costs.

Other Property—Other property includes autos, trucks, airplane, office furniture and computer equipment and other fixed assets. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from five to seven years.

Balance Sheet and Statement of Operations Information

Other balance sheet information is as follows:

	December 31, 2006	December 31, 2005
	(in thousands)	
Other Current Assets		
Derivative instruments	$ 35,242	$ 29,258
Materials and supplies inventories	46,973	33,802
Prepaid expenses and other	44,973	56,568
Total	$127,188	$119,628
Other Noncurrent Assets		
Equity method investments	$373,372	$420,362
Rabbi trust mutual fund investments	100,767	39,676
Probable insurance claims	46,500	112,800
Derivative instruments	2,862	17,259
Intangible asset related to employee benefit plans	—	3,827
Other assets	44,531	46,814
Total	$568,032	$640,738

	December 31, 2006	December 31, 2005
	(in thousands)	
Other Current Liabilities		
Accrued and other current liabilities	$219,885	$137,428
Interest payable	15,507	11,340
Total	$235,392	$148,768
Other Noncurrent Liabilities		
Deferred compensation liabilities	$173,253	$141,185
Accrued benefit costs	58,491	51,547
Other	42,976	87,239
Total	$274,720	$279,971

Other revenues and other expense, net consist of the following:

	Year ended December 31, 2006	2005	2004
		(in thousands)	
Other Revenues			
Electricity sales	$71,603	$74,228	$58,627
Gathering, marketing and processing	27,876	55,261	49,250
Total	$99,479	$129,489	$107,877
Other Expense, net			
Electricity generation [1]	$59,494	$53,137	$47,788
Gathering, marketing and processing	18,664	28,067	37,699
Deferred compensation expense	28,189	17,918	—
Impairment of operating assets	8,525	5,368	9,885
Other	18,680	3,917	4,991
Total	$133,552	$108,407	$100,363

[1] See "*Allowance for Doubtful Accounts*" above.

Goodwill—Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. We account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"). Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. During 2006, goodwill was increased by $38 million related to the acquisition of U.S. Exploration Holdings, Inc. ("U.S. Exploration"). It was reduced by $100 million allocated to the sale of Gulf of Mexico shelf properties and $20 million related to tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with our merger (the "Patina Merger") with Patina Oil & Gas Corporation ("Patina") and other tax adjustments. See Note 3—Acquisitions and Divestitures.

Income Taxes—Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was passed.

Fair Value of Financial Instruments—

The following methods and assumptions were used to estimate the fair values for each class of financial instruments. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between two willing parties.

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable—The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Long-Term Debt—The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues. The carrying amounts and estimated fair values of debt instruments were as follows:

	December 31,			
	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Long-term debt	$1,800,810	$1,852,890	$2,030,533	$2,097,060

See Note 7—Debt.

Derivative Instruments—The fair value estimates for commodity fixed price swaps, basis swaps and costless collars use market quotes and discount rates to determine discounted expected future cash flows as of the date of the estimate. See Note 12 — Derivative Instruments and Hedging Activities.

Capitalization of Interest—We capitalize interest costs associated with the development and construction of significant properties or projects to bring them to a condition and location necessary for their intended use, which for crude oil and natural gas assets is at first production from the field. Interest is capitalized using an interest rate equivalent to the average rate we pay on long-term debt, including the credit facility and bonds. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $13 million, $9 million and $8 million for 2006, 2005 and 2004, respectively.

Statement of Cash Flows—For purposes of reporting cash flows, cash and cash equivalents include unrestricted cash on hand and investments purchased with original maturities of three months or less.

Basic Earnings Per Share and Diluted Earnings Per Share—Basic earnings per share ("EPS") of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding common stock equivalents. The following table summarizes the calculation of basic EPS and diluted EPS components:

	Year ended December 31,					
	2006		2005		2004	
	Income	Shares	Income	Shares	Income	Shares
	(in thousands, except per share amounts)					
Net income available to common shareholders	$678,428	175,707	$645,720	153,773	$328,710	116,550
Basic EPS	$ 3.86		$ 4.20		$ 2.82	
Net income available to common shareholders	$678,428	175,707	$645,720	153,773	$328,710	116,550
Effect of dilutive stock options and restricted stock awards	—	3,337	—	2,986	—	1,902
Adjusted net income and shares	$678,428	179,044	$645,720	156,759	$328,710	118,452
Diluted EPS	$ 3.79		$ 4.12		$ 2.78	

The table below reflects the number of options, restricted stock and shares of Noble Energy common stock held in a rabbi trust excluded from the EPS calculation above for 2006 and 2005, as they were antidilutive. There were no antidilutive items for 2004.

	Weighted Outstanding Awards and Shares	Weighted Average Exercise Price
	(in thousands, except per share amounts)	
Year ended December 31, 2005		
Stock options	48	$41.47
Restricted stock	—	—
Noble Energy common stock held in rabbi trust	1,360	—
Total excluded from diluted EPS calculation	1,408	
Year ended December 31, 2006		
Stock options	675	$45.19
Restricted stock	14	—
Noble Energy common stock held in rabbi trust	1,262	—
Total excluded from diluted EPS calculation	1,951	

Accounting for Stock-Based Compensation—Through December 31, 2005, we accounted for stock-based compensation plans under the intrinsic value recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), and related Interpretations. As of January 1, 2006, we adopted SFAS No. 123(R), "Share-Based Payment" ("SFAS 123(R)"). SFAS 123(R) revised SFAS No. 123, "Accounting for Stock-Based Compensation" and nullified APB 25 and its related implementation guidance. SFAS 123(R) requires companies to measure the grant-date fair value of stock options and other stock-based compensation issued to employees and expense the fair value over the requisite service period of the award. SFAS 123(R) became effective for interim or annual periods beginning January 1, 2006. In accordance with the modified prospective transition method, prior period amounts have not been restated. See Note 9—Stock Option and Restricted Stock Plans, Incentive Plan and Stockholder Rights.

Accounting for Defined Benefit Pension and Other Postretirement Plans—In September 2006, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). SFAS 158 requires plan sponsors of defined benefit pension and other postretirement benefit plans to recognize the funded status of their postretirement benefit plans in the statement of financial position, measure the fair value of plan assets and benefit obligations as of the date of the fiscal year-end statement of financial position, and provide additional disclosures. We adopted SFAS 158 as of December 31, 2006, and the effect of adoption on our financial condition at December 31, 2006 has been included in our consolidated balance sheets. The effect of adoption included a $25 million decrease in other assets, a $28 million increase in accrued benefit costs, a $20 million decrease in deferred tax liabilities and a $33 million (net of tax of $20 million) decrease in shareholders' equity (effected by increasing AOCL). Adoption of SFAS 158 had no effect on our results of operations for the year ended December 31, 2006. SFAS 158's provisions regarding the change in the measurement date of postretirement benefit plans are not applicable as we already use a measurement date of December 31. See Note 11—Employee Benefit Plans.

Adoption of Staff Accounting Bulletin No. 108—In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). SAB 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant's approach. SAB 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB 108 is effective for fiscal years ending on or after November 15, 2006. We adopted SAB 108 as of December 31, 2006. Adoption of SAB 108 had no effect on our financial position or results of operations.

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

Revenue Recognition and Imbalances—We record revenues from the sales of crude oil and natural gas when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlements method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount sold by us in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount sold by us is recognized as revenue and a receivable is accrued. We record the noncurrent portion of the liability in other deferred credits and noncurrent liabilities, and the current portion of the liability in other current liabilities. We record the noncurrent portion of the receivable in other assets and the current portion of the receivable in other current assets. Imbalance liabilities were $17 million and $35 million at December 31, 2006 and 2005, respectively. Imbalance receivables were $18 million and $18 million at December 31, 2006 and 2005, respectively.

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

Noble Energy Marketing, Inc. ("NEMI"), a wholly-owned subsidiary, marketed approximately 43% of our domestic natural gas production in 2006. NEMI also engages in the purchase and sale of third-party crude oil and natural gas.

We record third-party sales, net of cost of goods sold, as gathering, marketing and processing revenues when the product is delivered or the contract is net settled at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

Derivative Instruments and Hedging Activities—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of commodity price fluctuations. Such instruments include variable to fixed NYMEX price swaps, costless collars and variable to fixed price 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. However, we are not able to predict sudden changes in counterparties' creditworthiness.

We account for derivative instruments and hedging activities in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended," ("SFAS 133"). SFAS 133 established accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded on the balance sheet as either an asset or liability measured at fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Under cash flow hedge accounting, gains and losses are reflected in shareholders' equity as accumulated other comprehensive income or loss ("AOCL") until the hedged transaction is recognized in earnings. The derivative's gains and losses are then offset against related results on the hedged transaction on the statements of operations. Gains and losses from derivative instruments related to crude oil and natural gas production and which qualify for hedge accounting treatment are recorded in oil and gas sales in the consolidated statements of operations upon sale of the associated products.

SFAS 133 also requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. We assess hedge effectiveness quarterly based on total changes in the derivative's fair value and using regression analysis. A hedge is considered effective if the resulting R-squared is above 80% and the slope is 80 - 120. We record hedge ineffectiveness in loss on derivative instruments. See Note 12—Derivative Instruments and Hedging Activities.

Related Party Transaction—Noble Energy entered into a consulting agreement with a former officer of Patina who now serves as a member of our Board of Directors. Pursuant to the consulting agreement, the Board member served as a consultant to the combined company for a period of 12 months following the merger (May 16, 2005) in exchange for a monthly retainer of $50,000. We paid total consulting fees of $225,806 during 2006 and $374,194 during 2005.

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

We self-insure the medical and dental coverage provided to certain employees, certain workers' compensation and the first $1.0 million of general liability coverage. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss.

Electricity Generation—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 natural gas to fuel the Machala power plant located in Machala, Ecuador. The revenues attributable to the natural gas-to-power project are included in "Other revenues" and the expenses (including DD&A) are included in "Other expense, net."

Concentration of Market Risk—During 2006, Trafigura Beheer B.V. was the largest single non-affiliated purchaser of production and accounted for 28% of crude oil sales, or 15% of total oil and gas sales. Shell Trading (US) Company accounted for 18% of 2006 crude oil sales or 10% of 2006 total oil and gas sales. During 2005, Glencore Energy U.K., Ltd. was the largest single non-affiliated purchaser of production and accounted for 24% of crude oil sales, or 11% of total oil and gas sales. During 2004, Marathon International Petroleum Supply Company (G.B.) Limited ("MIPSCO"), an affiliate of the operator of the Alba field in Equatorial Guinea, Marathon E. G. Production Ltd., accounted for 25% of crude oil sales, or 12% of total oil and gas sales. We believe the loss of any one purchaser would not have a material effect on our financial position or results of operation since there are numerous potential purchasers of our production.

Reclassification—Certain reclassifications have been made to the 2005 and 2004 consolidated financial statements to conform to the 2006 presentation. These reclassifications are not material to the financial statements.

Note 3—Acquisitions and Divestitures

Sale of Gulf of Mexico Shelf Properties—On July 14, 2006, we completed the sale of our Gulf of Mexico shelf properties. The sale included essentially all of our properties in the Gulf of Mexico shelf except for our interest in the Main Pass area, which we have retained. Pretax cash proceeds from the sale totaled $506 million including proceeds received from parties who exercised preferential rights to purchase certain minor properties. We recorded a pretax gain of $211 million from the sale. The net book value of assets sold totaled $229 million. Asset retirement obligations of $45 million, related to the Gulf of Mexico shelf properties, were also included in the sale. In accordance with SFAS 142, we allocated $100 million of our domestic reporting unit goodwill to the sale. The asset disposition did not qualify for accounting as discontinued operations, in accordance with EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations". This is due to the migration of our investment and operations to the Gulf Coast onshore and deepwater Gulf of Mexico areas.

As a result of the sale, we recognized a pretax charge of $399 million related to cash flow hedges which were reclassified from AOCL to earnings during the second quarter 2006. This reclassification reflected the mark-to-market value of the cash flow hedges that related to Gulf of Mexico shelf production. See Note 12—Derivative Instruments and Hedging Activities.

Purchase of U.S. Exploration Holdings, Inc.—On March 29, 2006, we purchased the common stock of U.S. Exploration, a privately held corporation located in Billings, Montana, for a cash purchase price of $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located in Colorado's Wattenberg field. The total purchase price was allocated preliminarily to the assets acquired and the liabilities assumed based on fair values at the acquisition date as follows:

- $413 million to proved oil and gas properties;
- $131 million to unproved oil and gas properties;
- $38 million to goodwill; and
- $172 million to deferred income taxes.

Certain data necessary to complete the final purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed and final tax returns that provide the underlying tax bases of assets and liabilities. We expect to complete the purchase price allocation during the twelve-month period following the acquisition date, during which time the preliminary allocation will be revised and goodwill will be adjusted, if necessary.

Patina Merger—On May 16, 2005, we completed the Patina Merger. Patina was an independent energy company engaged in the acquisition, development and exploitation of crude oil and natural gas properties within the continental U.S. Patina's properties and oil and gas reserves are principally located in relatively long-lived fields with established production histories. The properties are primarily concentrated in the Wattenberg field of Colorado's D-J Basin, the Mid-continent region of western Oklahoma and the Texas Panhandle, and the San Juan Basin in New Mexico. We acquired the common stock of Patina for a total purchase price of approximately $4.9 billion, which was comprised primarily of cash and Noble Energy common stock, plus liabilities assumed. In exchange for Patina's common stock and stock options held by Patina's employees, we issued 55.7 million shares of stock valued at $1.7 billion, issued options valued at $105 million, paid $1.1 billion in cash to Patina shareholders and assumed debt of $611 million and deferred taxes of $1.1 billion. The total purchase price was allocated to the assets acquired and the liabilities assumed based on fair values at the merger date as follows:

- $2.642 billion to proved oil and gas properties;
- $1.068 billion to unproved oil and gas properties;
- $875 million to goodwill; and
- $1.108 billion to deferred income taxes.

The amount of goodwill recorded in the Patina Merger has been reduced by $27 million ($15 million in 2006) for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the merger.

Pro Forma Financial Information—The following pro forma condensed combined financial information for the years ended December 31, 2005 and 2004 was derived from our historical financial statements and those of Patina and gives effect to the merger as if it had occurred on January 1, 2004. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the merger taken place as of the dates indicated and is not intended to be a projection of future results.

	Year ended December 31,	
	2005	2004
	(in thousands, except per share amounts)	
Revenues	$ 2,434,677	$ 1,913,786
Income from continuing operations	693,091	387,566
Net income	693,091	402,426
Earnings per share:		
Basic	$ 4.03	$ 2.38
Diluted	3.98	2.30

Note 4—Effect of Gulf Coast Hurricanes

2005 Hurricane Activity—In August 2005, Hurricane Katrina moved through the Gulf of Mexico and caused the loss of the Main Pass 306D platform. The net book value of the platform was $15 million. Clean-up costs associated with the damage resulted in an increase to the Main Pass 306D asset retirement obligation of $66 million. We accounted for the net book value of the destroyed platform and the increase in asset retirement costs as a loss on involuntary conversion.

As of December 31, 2006, we have incurred $79 million (cumulative) in costs related to Hurricane Katrina damage, $16.5 million of which has been approved and reimbursed by our insurance carriers. During 2005, we were notified by one of our insurance carriers that its maximum exposure limit for losses incurred during Hurricane Katrina had been reached and that, consequently, our final insurance recovery will be limited. As of December 31, 2006, we have recorded probable insurance claims of $64 million, the estimated remaining recovery for losses sustained from Hurricane Katrina. Total Hurricane Katrina costs for clean-up, repair and redevelopment are currently estimated at approximately $183 million. We expect to complete clean-up work during 2007 and receive final reimbursements thereafter.

Hurricane Rita struck the Gulf Coast in September 2005 and caused minor damage to our Gulf of Mexico assets. As of December 31, 2006, based upon work completed, we have incurred $8 million (cumulative) in costs related to Hurricane Rita damage. We expect our insurance carrier to approve and reimburse these costs subject to our $1 million deductible.

2004 Hurricane Activity—In September 2004, Hurricane Ivan caused infrastructure damage at Main Pass 293/305/306. The net book value of the property was $24 million. The remediation work began second quarter 2005, and we commenced production from undamaged platforms in the third quarter 2005.

As of December 31, 2006, based upon work completed, we have incurred $203 million (cumulative) in costs related to Hurricane Ivan damage. Our insurance carriers have approved and reimbursed $176 million of these costs with the balance pending subsequent review and approval. We expect to complete clean-up work during 2007 and receive final reimbursements thereafter.

Amounts related to involuntary conversions caused by Hurricanes Katrina and Ivan are as follows:

	Year ended December 31,	
	2005	2004
Net book value of assets impaired or destroyed	$ 14,500	$ 23,978
Increase in asset retirement obligation related to hurricane damage	66,000	130,000
Loss on involuntary conversion of assets	80,500	153,978
Income from probable insurance claims	(79,500)	(152,978)
Net loss on involuntary conversion of assets	$ 1,000	$ 1,000

Assets (liabilities) related to the hurricane insurance recoveries and included in the consolidated balance sheets consist of the following:

	December 31,	
	2006	2005
	(in thousands)	
Probable insurance claims—current	$ 101,233	$ 142,311
Other assets (long-term portion of probable insurance claims)	46,500	112,800
Total expected hurricane insurance recoveries	$ 147,733	$ 255,111
Asset retirement obligations—current	$ (65,120)	$ (42,016)
Asset retirement obligations—long-term	—	(121,800)
Total asset retirement obligations related to hurricane damage	$ (65,120)	$ (163,816)

Note 5—Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial, in which case the well costs are immediately charged to exploration expense.

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Capitalized exploratory well costs, beginning of period	$ 35,228	$ 62,724	$ 29,375
Additions to capitalized exploratory well costs pending determination of proved reserves	62,580	33,671	45,011
Reclassified to property, plant and equipment based on determination of proved reserves	(16,762)	(52,138)	(1,061)
Capitalized exploratory well costs charged to expense	(687)	(9,029)	(10,601)
Capitalized exploratory well costs, end of period	$ 80,359	$ 35,228	$ 62,724

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

	December 31,		
	2006	2005	2004
	(in thousands)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$58,493	$35,228	$44,986
Capitalized exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	21,866	—	17,738
Balance at end of period	$80,359	$35,228	$62,724
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	4	—	4

Included in the capitalized exploratory well costs capitalized for more than one year at December 31, 2006 were four projects. One of the projects, Blocks O and I, which includes approximately $20 million, is located offshore Equatorial Guinea. Since drilling the initial well, additional seismic work has been completed and current plans are to drill an appraisal well in 2007 to further evaluate this apparent discovery. The remaining three projects, which total approximately $2 million, are all located in Alabama and are currently waiting on sales lines.

The four projects as of December 31, 2004 that had exploratory costs greater than one year were reclassified to property, plant and equipment during 2005 when proved reserves were recorded.

Note 6—Asset Retirement Obligations

Asset retirement obligations consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset.

Changes in asset retirement obligations were as follows:

	Year ended December 31, 2006
	(in thousands)
Asset retirement obligations, beginning of period	$ 338,871
Liabilities incurred in current period	4,086
Liabilities transferred in sale of Gulf of Mexico shelf properties	(44,521)
Liabilities settled in current period	(150,847)
Revisions	37,803
Accretion expense	10,797
Asset retirement obligations, end of period	$ 196,189
Current portion	$ 68,500
Noncurrent portion	127,689

Revisions during 2006 resulted from changes in estimated timing of actual abandonment and overall cost increases. The ending aggregate carrying amount at December 31, 2006 included $65 million, which we expect to be reimbursed by insurance, related to damage to the Main Pass assets caused by Hurricanes Ivan and Katrina in the Gulf of Mexico. See Note 4—Effect of Gulf Coast Hurricanes.

Note 7—Debt

Our debt consists of the following:

	December 31, 2006 Debt	2006 Interest Rate	December 31, 2005 Debt	2005 Interest Rate
	(in thousands, except percentages)			
$2.1 billion Credit Facility, due December 2011	$1,155,000	5.69	$1,280,000	4.82
5 ¼% Senior Notes, due April 2014	200,000	5.25	200,000	5.25
7 ¼% Notes, due October 2023	100,000	7.25	100,000	7.25
8% Senior Notes, due April 2027	250,000	8.00	250,000	8.00
7 ¼% Senior Debentures, due August 2097	100,000	7.25	100,000	7.25
Term Loans, due January 2009	—	—	105,000	5.23
Outstanding debt	1,805,000		2,035,000	
Unamortized discount	(4,190)		(4,467)	
Long-term debt	$1,800,810		$2,030,533	

All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest. The indenture documents of each of the 7¼% Notes, the 8% Senior Notes and the 7¼% Senior Debentures provide that we may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually.

Credit Facility—In November 2006, we amended our $2.1 billion unsecured five-year revolving credit facility (the "Credit Facility"). The Credit Facility, as amended, (i) extends the maturity date of the Credit Facility to December 9, 2011, (ii) provides for Credit Facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (iii) makes available swingline loans up to an aggregate amount of $300 million and (iv) 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 amendment to the Credit Facility eliminated the financial covenant requiring a 4.0 to 1.0 ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense to interest expense. However, the Credit Facility continues to require that our total debt to capitalization ratio, expressed as a percentage, not exceed 60% at any time. A violation of this covenant could result in a default under the Credit Facility, which would permit the participating banks to restrict our ability to access the Credit Facility and require the immediate repayment of any outstanding advances under the Credit Facility. The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes.

Certain lenders that are a party to the Credit Facility have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for us, for which they have received, and may in the future receive, customary compensation and reimbursement of expenses. Debt issuance costs of approximately $3 million remain and are being amortized to expense over the life of the Credit Facility.

The Credit Facility does not restrict the payment of dividends on Noble Energy common stock, except, if after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby.

Debt Repayments—During 2006, we prepaid the $105 million balance remaining on the Term Loans due 2009. The Term Loans consisted of term loan agreements entered into between our subsidiary, Noble Energy Mediterranean Ltd., and several commercial lending institutions in 2004. The original amount of the Term Loans was $150 million, and we prepaid $45 million of the Term Loans in 2005. The interest rates on the Term Loans were based on a Eurodollar rate plus an effective range of 60 to 130 basis points depending upon our credit rating. Interest was payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of a rate reset.

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

	(in thousands)
2007	$ —
2008	—
2009	—
2010	—
2011	1,155,000
Thereafter	650,000
Total	$1,805,000

Short-Term Borrowings—Our credit agreement is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no short-term borrowings outstanding at December 31, 2006 or 2005.

Note 8—Income Taxes

Components of income before income taxes are as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Domestic	$ 402,111	$426,756	$254,582
Foreign	694,106	541,904	258,426
Total	$1,096,217	$968,660	$513,008

The income tax provision consists of the following:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Current taxes:			
Federal	$ 79,680	$ 48,293	$136,858
State	5,577	—	6,930
Foreign	138,271	90,877	39,624
Total current	223,528	139,170	183,412
Deferred taxes:			
Federal	144,143	119,953	1,192
State	4,641	14,073	(702)
Foreign	45,477	49,744	23,258
Total deferred	194,261	183,770	23,748
Total income tax provision	$417,789	$322,940	$207,160
Income tax provision associated with continuing operations	$417,789	$322,940	$199,158
Income tax provision associated with discontinued operations	—	—	8,002
Total income tax provision	$417,789	$322,940	$207,160

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

	2006	2005	2004
	(amounts in percentages)		
Federal statutory rate	35.0	35.0	35.0
Effect of:			
Earnings of equity method investees	(4.2)	(3.2)	(4.5)
State taxes, net of federal benefit	1.3	1.3	0.7
Difference between U.S. and foreign rates	2.2	3.5	10.1
Nondeductible goodwill	3.1	—	—
AJCA repatriation benefit	—	(3.7)	—
Release of China valuation allowance	—	—	(2.7)
Other, net	0.7	0.4	0.2
Effective rate	38.1	33.3	38.8

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2006	2005
	(in thousands)	
Deferred tax assets:		
Foreign loss carryforward	$ 90,387	$ 3,431
Foreign and state income tax accruals	8,882	8,884
Accrued expenses	22,535	39,636
Deferred income	2,666	1,916
Allowance for doubtful accounts	2,917	3,152
Fair value of derivative contracts	185,667	448,240
Postretirement benefits	14,578	23,011
Deferred compensation	55,880	43,567
Foreign tax credits	10,852	5,598
Future foreign tax credits from foreign branch deferred tax liabilities	52,855	54,882
Other	3,577	1,067
Total deferred tax assets	450,796	633,384
Valuation allowance	(73,584)	(48,386)
Net deferred tax assets	377,212	584,998
Deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(2,034,877)	(1,546,062)
Other	(952)	(3,082)
Total deferred tax liability	(2,035,829)	(1,549,144)
Net deferred tax asset (liability)	$(1,658,617)	$ (964,146)

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

	2006	2005
	(in thousands)	
Deferred income tax asset	$ 99,835	$ 237,045
Deferred income tax liability	(1,758,452)	(1,201,191)
Net deferred tax liability	$(1,658,617)	$ (964,146)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2006. The amount of the deferred tax asset considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

We have recognized deferred tax assets associated with foreign loss carryforwards. The tax effect of these carryforwards increased from $3 million in 2005 to $90 million in 2006 The foreign loss carryforward related to China was fully utilized in 2005. However, we incurred losses on our project in Suriname and on other new venture activities which are not yet commercial. Therefore, a valuation allowance of $10 million was provided against the tax benefits of those losses. In addition, we incurred a large taxable loss in the UK during 2006 from accelerated write-offs allowed on our Dumbarton field development. No valuation allowance has been provided against this loss carryforward because we expect to utilize it in 2007, and the carryforward period is unlimited. Starting in 2005, we were able to claim a foreign tax credit for U.S. federal income tax purposes and expect to be in a credit position for the next several years. Therefore, we have recorded a deferred tax asset for certain foreign taxes paid in 2005 and 2006 that cannot be claimed as a credit in those years because of limitations imposed by the Internal Revenue Code. A valuation allowance of $7 million has been provided against this deferred tax asset. We have also recorded a deferred tax asset of $53 million for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations. A valuation allowance of $53 million has been provided against this deferred tax asset.

Several factors resulted in an increase in our effective tax rate for 2006. The major factor was the allocation of $100 million of nondeductible goodwill to the sale of the Gulf of Mexico shelf properties. In addition, an increase in a deferred tax asset valuation allowance contributed to the increase in the effective rate. At December 31, 2005, we had recorded a deferred U.S. tax asset of $55 million for the future foreign tax credits associated with deferred foreign tax liabilities recorded by our foreign branch operations. The valuation allowance with respect to the deferred U.S. tax asset was $41 million at December 31, 2005. The tax asset was decreased to $53 million during 2006, and the valuation allowance was increased to $53 million due to changes in the forecast of limitations on the ability to claim foreign tax credits. There was also an increase in the UK tax rate during 2006. The UK Finance Act of 2006, enacted on July 19, increased the income tax rate on our UK operations retroactive to January 1, 2006 and increased our income tax provision by approximately $9 million in 2006. Partially offsetting these increases was a benefit from the realization of additional income from equity method investees which is a favorable permanent difference in calculating the income tax expense.

The American Jobs Creation Act ("AJCA"), enacted in 2004, created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing for an 85% dividends-received deduction for certain dividends from controlled foreign corporations. In July 2005, we completed an evaluation of the effects of the repatriation provision, and our Board of Directors approved a plan to repatriate $118 million in earnings of our methanol subsidiary during the third quarter 2005. Because we had provided U.S. tax on most of the methanol subsidiary's earnings at 35% through December 31, 2004, repatriation under the Act resulted in a net tax benefit of $35 million recorded in the third quarter 2005.

We have not recorded U.S. deferred income taxes on the remaining undistributed earnings of foreign subsidiaries as of December 31, 2006. As of December 31, 2006, the accumulated undistributed earnings of the consolidated foreign subsidiaries were approximately $543 million. Upon distribution of these earnings in the form of dividends or otherwise, we may be subject to U.S. income taxes and foreign withholding taxes. It is not practicable, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of U.S. foreign tax credits. Although we are currently claiming foreign tax credits, we may not be in a credit position when any future remittance of foreign earnings takes place.

Note 9—Stock Option and Restricted Stock Plans, Incentive Plan and Stockholder Rights

As discussed in Note 2—Summary of Significant Accounting Policies, effective January 1, 2006, we adopted the fair value recognition provisions for stock-based awards granted to employees using the modified prospective application method provided by SFAS 123(R). Accordingly, prior period amounts have not been restated. SFAS 123(R) requires companies to recognize in the statement of operations the grant-date fair value of stock options and other stock-based compensation issued to employees and was effective for interim or annual periods beginning January 1, 2006. We recognize the expense of all stock-based awards on a straight-line basis over the employee's requisite service period (generally the vesting period of the award).

We recognized total stock-based compensation expense as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Stock-based compensation expense included in:			
General and administrative expense	$10,720	$4,008	$868
Exploration expense and other	1,096	—	—
Total stock-based compensation expense	$11,816	$4,008	$868
Tax benefit recognized	$ 4,443	$1,403	$269

As a result of adopting SFAS 123(R) on January 1, 2006, our income before income taxes, net income and earnings per share were lower than if we had continued to account for stock-based compensation under APB 25. The impact on our financial results related to the adoption of SFAS 123(R) is as follows:

	Year ended December 31,
	2006
	(in thousands, except (per share amounts)
Decrease in income:	
Income before taxes	$6,248
Net income	3,902
Basic earnings per share	0.02
Diluted earnings per share	0.02

Prior to the adoption of SFAS 123(R), we presented tax benefits resulting from exercise of stock options or vesting of restricted stock as cash flows from operating activities within our consolidated statements of cash flows. SFAS 123(R) requires the cash flows resulting from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for stock-based awards (excess tax benefits) to be classified as cash flows from financing activities. Tax benefits presented as cash flows from financing activities totaled $26 million in our 2006 consolidated statement of cash flows. This amount would have been presented as cash flows from operating activities if we had continued to account for stock-based compensation under APB 25. In addition, tax benefits of $15 million and $12 million related to the exercise of fully-vested options assumed in the Patina Merger reduced goodwill during 2006 and 2005, respectively.

The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS 123(R) to stock-based employee compensation in all periods presented. The actual and pro forma net income and earnings per share for 2006 below are the same since we adopted SFAS 123(R) as of January 1, 2006. The 2006 amounts are presented for comparison to prior years.

	Year ended December 31,		
	2006	2005	2004
	(actual)	(pro forma)	
	(in thousands, except per share amounts)		
Net income, as reported	$678,428	$645,720	$328,710
Add: Stock-based compensation cost recognized, net of tax	7,373	2,605	599
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(7,373)	(6,150)	(5,752)
Pro forma net income	$678,428	$642,175	$323,557
Earnings per share:			
Basic - as reported	$ 3.86	$ 4.20	$ 2.82
Basic - pro forma	3.86	4.18	2.78
Diluted - as reported	3.79	4.12	2.78
Diluted - pro forma	3.79	4.10	2.73

Total stock-based employee compensation expense determined under the fair value based method for all awards for 2005 and 2004 has been recalculated using revised expected term assumptions. The impact on pro forma earnings and pro forma earnings per share was not significant.

Our stock option and restricted stock plans (the "Plans") and incentive plan are described below.

1992 Stock Option and Restricted Stock Plan

Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the "1992 Plan"), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the "Committee") may grant stock options and award restricted stock to officers or other employees of Noble Energy and its subsidiaries. The maximum number of shares of common stock that may be issued under the 1992 Plan is 18,500,000 shares. At December 31, 2006, 8,231,995 shares of common stock were reserved for issuance, including 4,462,143 shares available for future grants and awards, under the 1992 Plan.

1992 Plan Stock Options—Stock options are issued with an exercise price equal to the market price of Noble Energy common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire ten years from the grant date. Option grants generally vest ratably over a three-year period.

1992 Plan Restricted Stock—Restricted stock awards made under the 1992 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. Restricted Stock awards generally vest over periods of one to three years.

2004 Long-Term Incentive Plan

Under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (the "2004 LTIP"), the Committee may make incentive awards to key employees of Noble Energy and its subsidiaries. Incentive compensation is based upon the attainment of specific market and performance goals established by the Committee. Awards may be in the form of stock options or restricted stock or in the form of performance units or other incentive measurements providing for the payment of bonuses in cash, or in any combination thereof, as determined by the Committee in its discretion. Stock options granted and restricted stock awarded under the 2004 LTIP are granted and awarded pursuant to the terms of the 1992 Plan. These awards are accounted for in accordance with the provisions of SFAS 123(R) which provides for the grant-date fair value of the awards to be recognized in the income statement over the service period. Our cash based performance units are accounted for under SFAS No. 5, "Accounting for Contingencies" and are excluded from the provisions of SFAS 123(R).

2005 Stock Plan for Non-Employee Directors

The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (the "2005 Plan") provides for grants of stock options and awards of restricted stock to non-employee directors of Noble Energy. The 2005 Plan superseded and replaced the 1988 Nonqualified Stock Option Plan for Non-Employee Directors. The total number of shares of common stock that may be issued under the 2005 Plan is 800,000. At December 31, 2006, 785,600 shares of common stock were reserved for issuance, including 715,180 shares available for future grants and awards under the 2005 Plan.

2005 Plan Stock Options—The 2005 Plan provides for the granting to a non-employee director of 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 11,200 options per non-employee director granted in any one year). Options are issued with an exercise price equal to the market price of Noble Energy common stock on the date of grant and may be exercised one year after the date of grant. The options expire ten years from the date of grant.

2005 Plan Restricted Stock—The 2005 Plan also provides for the granting to a non-employee director of 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 4,800 shares of restricted stock per non-employee director awarded in any one year). Restricted stock is restricted for a period of at least one year from the date of grant.

1988 Nonqualified Stock Option Plan

The 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc., as amended, (the "1988 Plan") provided for the issuance of stock options to non-employee directors of Noble Energy. Options issued under the 1988 Plan may be exercised one year after grant and expire ten years from the grant date. The 1988 Plan provided for the granting of a fixed number of stock options to each non-employee director annually (10,000 stock options for the first calendar year of service and 5,000 stock options for each year thereafter) on February 1 of each year. The 1988 Plan was terminated in 2005. No options can be granted under the 1988 Plan after its termination.

Patina Stock Option Plans

Patina maintained a shareholder approved stock option plan for employees (the "Patina Employee Plan") that provided for the issuance of options at prices not less than fair market value at the date of grant. Patina also maintained a shareholder approved stock grant and option plan for non-employee directors (the "Patina Directors' Plan"). The Patina Directors' Plan provided for stock options to be granted to each non-employee director upon appointment and upon annual re-election thereafter. Upon completion of the Patina Merger, all unvested stock options outstanding under the Patina Employee Plan and the Patina Directors' Plan became fully vested, and all outstanding options were converted into options to purchase Noble Energy common stock. The Patina options expire five years from the date of grant. See Note 3—Acquisitions and Divestitures.

Stock Option Grants

The fair value of each option award was estimated on the date of grant using a Black-Scholes-Merton option valuation model that uses the assumptions noted in the following table. The expected term represents the period of time that options granted are expected to be outstanding. The hypothetical midpoint scenario we use considers the actual exercise and post-vesting cancellation history of stock-based compensation historical trends to develop expectations for future periods. Expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the anticipated term of the award. We used the historical volatility of Noble Energy common stock for the 5.5-year period ended prior to the date of grant. The risk-free rate is based on a weighting of five and seven year U.S. Treasury securities as of the year ended prior to the date of grant to arrive at an approximated 5.5-year risk free rate of return. The dividend yield represents the value of our stock's annualized dividend as compared to our stock's average price for the three-year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three-year period ended prior to the date of grant.

Assumptions - Stock Option Grants	2006	2005	2004
	(weighted averages)		
Expected term (in years)	5.5	5.5	5.5
Expected volatility	31.8%	21.5%	21.4%
Risk-free rate	4.7%	4.6%	4.8%
Expected dividend yield	0.8%	0.4%	0.3%

A summary of option activity follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(years)	(in thousands)
Outstanding at December 31, 2005	9,319,642	$19.21		
Granted	832,719	45.26		
Exercised	(3,848,521)	16.27		
Forfeited	(92,090)	38.40		
Canceled / expired	—	—		
Outstanding at December 31, 2006	6,211,750	$24.24	4.7	$155,715
Exercisable at December 31, 2006	4,869,657	$20.39	3.6	$140,829

The weighted-average grant-date fair value of options granted during 2006, 2005 and 2004 was $16.09, $12.17, and $9.27, respectively. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $118 million, $78 million, and $66 million, respectively.

As of December 31, 2006, there was $11 million of total unrecognized compensation cost related to unvested stock options granted under the Plans. The cost is expected to be recognized over a weighted-average period of 1.4 years. We issue new shares of common stock to settle option exercises. Dividends are not paid on unexercised options.

Options exercised during 2006 included 2,929,516 options held by Patina employees which had been converted into options for Noble Energy common stock at the date of the Patina Merger.

Restricted Stock Awards

Awards of time-vested restricted stock are valued at the price of our common stock at the date of award. The fair values of market based restricted stock awards are estimated on the date of award using a Monte Carlo valuation model that uses the assumptions in the following table. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility represents the extent to which our stock price is expected to fluctuate between now and the award's anticipated term. We use the historical volatility of Noble Energy common stock for the three-year period ended prior to the date of award. The risk-free rate is based on a three-year period from U.S. Treasury securities as of the year ended prior to the date of award.

Assumptions - Market Based Restricted Stock Awards	2006	2005	2004
Number of simulations	100,000	100,000	100,000
Expected volatility	28.4%	29.6%	37.2%
Risk-free rate	4.4%	3.3%	2.5%

A summary of restricted stock activity follows:

	Subject to Service Conditions	Weighted Average Grant Date Fair Value	Subject to Market Conditions	Weighted Average Grant Date Fair Value
	(shares)		(shares)	
Restricted stock at December 31, 2005	123,246	$33.79	133,515	$23.60
Awarded	12,039	45.45	77,563	39.51
Vested	(45,472)	33.44	—	—
Forfeited	(16,718)	33.44	(6,828)	34.59
Outstanding at December 31, 2006	73,095	$35.85	204,250	$29.27

The total fair value of restricted stock that vested during 2006 was $2 million.

As of December 31, 2006, there was $3 million of total unrecognized compensation cost related to unvested restricted stock awarded under the Plans. The cost is expected to be recognized over a weighted-average period of 1.7 years. Common stock dividends accrue on restricted stock grants and are paid upon vesting. We issue new shares of common stock when awarding restricted stock.

Stockholder Rights Plan—We adopted a stockholder rights plan on August 27, 1997 designed to assure that our stockholders receive fair and equal treatment in the event of any proposed takeover of Noble Energy and to guard against partial tender offers and other abusive takeover tactics to gain control of Noble Energy without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, we declared a dividend of one right ("Right") on each share of Noble Energy common stock. Each Right will entitle the holder to purchase one one-hundredth of a share of a new Series A Junior Participating Preferred Stock, par value $1.00 per share, at an exercise price of $150 per share. The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires beneficial ownership of 15% or more of Noble Energy common stock. The dividend distribution was made on September 8, 1997, to stockholders of record at the close of business on that date. The Rights will expire on September 8, 2007.

Note 10—Additional Shareholders' Equity Information

The following table reflects the activity in shares (as adjusted for the two-for-one stock split, effected in the form of a stock dividend, in third quarter 2005) of Noble Energy common stock and treasury stock:

	Year Ended December 31,	
	2006	2005
Common Stock:		
Shares at beginning of period	184,893,510	125,144,834
Shares issued in Patina Merger	—	55,670,408
Exercise of common stock options	3,848,521	3,903,889
Restricted stock awards, net of forfeitures	66,056	174,379
Shares at end of period	188,808,087	184,893,510
Treasury Stock:		
Shares at beginning of period	9,268,932	7,099,952
Shares repurchased	8,373,400	—
Shares issued in Patina Merger	—	2,189,414
Rabbi trust shares sold	(1,067,948)	(20,434)
Shares at end of period	16,574,384	9,268,932

On May 16, 2006, we announced that our Board of Directors had authorized the repurchase of up to $500 million of common stock. We may buy shares from time to time on the open market or in negotiated purchases and expect to fund the repurchases primarily from cash flows from operations. The timing and amounts of any repurchases will be at management's discretion and in accordance with securities laws and other legal requirements. The repurchase program is subject to reevaluation in the event of changes in market conditions. During 2006, we repurchased 8,373,400 shares of our common stock at an aggregate cost of $399 million. We repurchased an additional 1,790,000 shares of common stock at an aggregate cost of $89 million during the period January 1, 2007 through February 12, 2007.

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

	Accumulated Other Comprehensive Loss			
	Oil and Gas Cash Flow Hedges	Interest Rate Lock Cash Flow Hedge	Minimum Pension Liability and Other	Total
	(in thousands)			
December 31, 2003	$ (7,618)	$ (2,508)	$ (760)	$ (10,886)
Cash flow hedges				
Realized amounts reclassified into earnings	39,840	348	—	40,188
Unrealized change in fair value	(39,161)	(2,417)	—	(41,578)
Net change in minimum pension liability and other	—	—	(2,511)	(2,511)
December 31, 2004	(6,939)	(4,577)	(3,271)	(14,787)
Cash flow hedges				
Realized amounts reclassified into earnings	154,500	492	—	154,992
Unrealized amounts reclassified into earnings	33,638	—	—	33,638
Unrealized change in fair value	(945,033)	—	—	(945,033)
Net change in minimum pension liability and other			(12,309)	(12,309)
December 31, 2005	(763,834)	(4,085)	(15,580)	(783,499)
Cash flow hedges				
Realized amounts reclassified into earnings	145,035	637	—	145,672
Unrealized amounts reclassified into earnings	264,520	—	—	264,520
Unrealized change in fair value	249,974	—	—	249,974
Net change in minimum pension liability and other	—	—	16,225	16,225
Adoption of SFAS 158	—	—	(33,401)	(33,401)
December 31, 2006	$(104,305)	$ (3,448)	$(32,756)	$(140,509)

The effective income tax rate applied to AOCL was increased from 35% at December 31, 2005 to 37.6% at December 31, 2006.

Note 11—Employee Benefit Plans

Pension Plan and Other Postretirement Benefit Plans—We have a noncontributory, tax-qualified defined benefit pension plan covering certain domestic employees. The benefits are based on an employee's years of service and average earnings for the 60 consecutive calendar months of highest compensation. Our funding policy has been to make annual contributions equal to at least the minimum required contribution, but no greater than the maximum deductible for federal income tax purposes. During 2006 we contributed $34 million to the qualified defined benefit pension plan. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by ERISA. We sponsor other plans for the benefit of our employees and retirees, which include health care and life insurance benefits. We use a December 31 measurement date for the plans.

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

On December 31, 2006, we adopted SFAS 158 as discussed in Note 2—Summary of Significant Accounting Policies. SFAS 158 requires us to recognize the funded status (the difference between the fair value of plan assets and the benefit obligation) of our defined benefit pension, restoration and other postretirement benefit plans in the December 31, 2006 consolidated balance sheet, with a corresponding adjustment to AOCL, net of tax. The adjustment to AOCL at adoption represents the unrecognized net actuarial loss, unrecognized prior service costs, and unrecognized net transition obligation remaining from the initial adoption of SFAS No. 87, "Employers' Accounting for Pensions" ("SFAS 87") and SFAS No. 106, "Employers' Accounting for Post-Retirement Benefits Other Than Pensions" ("SFAS 106"). These amounts will be subsequently recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic benefit cost in the same periods will be recognized as a component of AOCL.

The incremental effects of adopting the provisions of SFAS 158 on our consolidated balance sheet at December 31, 2006 are presented in the following table. The adoption of SFAS 158 had no effect on our consolidated statements of operations for the year ended December 31, 2006, or for any prior period presented, and it will not affect our operating results in future periods. Had we not been required to adopt SFAS 158 at December 31, 2006, we would have recognized an additional minimum liability for the restoration plan pursuant to the provisions of SFAS 87. The effect of recognizing an additional minimum liability for the restoration plan is included in the table below in the column labeled "Prior to Adoption of SFAS 158."

	December 31, 2006		
	Prior to Adoption of SFAS 158	Effect of Adoption of SFAS 158	As Reported at December 31, 2006
		(in thousands)	
Other noncurrent assets	$ 593,125	$(25,093)	$ 568,032
Total assets	9,613,718	(25,093)	9,588,625
Other current liabilities	(233,246)	(2,146)	(235,392)
Total current liabilities	(1,182,116)	(2,146)	(1,184,262)
Deferred income tax liability	(1,778,579)	20,127	(1,758,452)
Other noncurrent liabilities	(248,431)	(26,289)	(274,720)
Total liabilities	(5,466,500)	(8,308)	(5,474,808)
AOCL, net of tax	107,108	33,401	140,509
Total shareholders' equity	(4,147,218)	33,401	(4,113,817)

The following table presents amounts included in AOCL at December 31, 2006 that have not yet been recognized in net periodic benefit cost and the amounts that are expected to be recognized in net periodic benefit cost during the year ended December 31, 2007:

	Retirement and Restoration Plan	Medical and Life Plan
	(in thousands)	
Net amounts included in AOCL that have not yet been recognized in net periodic benefit cost (pre-tax)		
Unrecognized net transition obligation	$ 854	$ —
Unrecognized prior service credit	(5,372)	(6,672)
Unrecognized loss	49,977	17,384
Total	$45,459	$10,712
Amounts expected to be recognized in net periodic benefit cost in 2007		
Unrecognized net transition obligation	$ 239	$ —
Unrecognized prior service credit	(516)	(926)
Unrecognized loss	3,221	1,211
Total	$ 2,944	$ 285

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

	Retirement and Restoration Plan		Medical and Life Plan	
	2006	2005	2006	2005
	(in thousands)			
Change in projected benefit obligation				
Benefit obligation at beginning of year	$168,301	$132,746	$ 27,223	$ 11,715
Service cost	11,781	6,372	2,207	963
Interest cost	9,550	7,807	1,377	943
Amendments	(8,327)	614	(5,711)	—
Employee contributions	—	—	272	223
Actuarial (gain) loss	18	26,158	(2,200)	14,113
Benefits paid	(6,169)	(5,396)	(795)	(734)
Benefit obligation at end of year	$175,154	$168,301	$ 22,373	$ 27,223
Change in plan assets				
Fair value of plan assets at beginning of year	94,832	81,115	—	—
Actual return on plan assets	12,593	5,725	—	
Employer contributions	35,634	13,388	523	511
Employee contributions	—	—	272	223
Benefits paid	(6,169)	(5,396)	(795)	(734)
Fair value of plan assets at end of year	$136,890	$ 94,832	$ —	$ —
Funded status	$ (38,264)	(73,469)	$(22,373)	(27,223)
Unrecognized net actuarial loss	*	56,144	*	20,754
Unrecognized prior service cost (benefit)	*	2,734	*	(1,399)
Unrecognized net transition obligation	*	1,093	*	—
Net amount recognized	*	$ (13,498)	*	$ (7,868)
Net amount recognized in statement of financial position consists of:				
Noncurrent assets	$ —	*	$ —	*
Current liabilities	(1,205)	*	(941)	*
Noncurrent liabilities	(37,059)	*	(21,432)	*
Accrued benefit cost	*	$ (43,679)	*	$ (7,868)
Intangible asset	*	3,827	*	—
Pre-tax amount included in AOCL	*	26,354	*	—
Net amount recognized	*	$ (13,498)	*	$ (7,868)
Accumulated benefit obligation	$142,136	$138,511	$ —	$ —
Information for pension plans with projected benefit obligations in excess of plan assets				
Projected benefit obligation	$175,154	$168,301	$ —	$ —
Fair value of plan assets	136,890	94,832	—	—
Information for pension plans with accumulated benefit obligations in excess of plan assets				
Accumulated benefit obligation	$ 20,542	$138,511	$ —	$ —
Fair value of plan assets	—	94,832	—	—

* Not applicable due to change in method of accounting for defined benefit pension and other postretirement plans.

Accrued benefit costs are included in other current liabilities ($2 million) and other long-term liabilities ($58 million) in the consolidated balance sheets. No plan assets are expected to be returned to us during 2007.

Net periodic benefit cost recognized for the pension, restoration and other postretirement benefit plans is provided in the table below. Net periodic benefit cost includes plan design changes made effective May 1, 2006.

	Retirement and Restoration Plan			Medical and Life Plan		
	2006	2005	2004	2006	2005	2004
	(in thousands)					
Service cost	$ 11,781	$ 6,372	$ 6,248	$ 2,207	$ 963	$ 610
Interest cost	9,550	7,807	7,303	1,377	943	577
Expected return on plan assets	(9,320)	(7,094)	(6,745)	—	—	—
Transition obligation recognition	239	24	25	—	—	—
Amortization of prior service cost	(220)	398	353	(439)	(236)	(236)
Recognized net actuarial loss	2,912	1,034	560	1,170	760	363
Net periodic benefit cost	$ 14,942	$ 8,541	$ 7,744	$ 4,315	$2,430	$1,314
Additional Information						
Increase in minimum liability included in AOCL	*	$21,638	$ 4,716	*	$ —	$ —
Weighted-average assumptions used to determine benefit obligations at December 31,						
Discount rate	5.75%	5.50%	6.00%	5.75%	5.50%	5.75%
Rate of compensation increase	5.00%	5.00%	4.00%	—	—	—
Weighted-average assumptions used to determine net periodic benefit costs for year ended December 31,						
Discount rate [1]	5.50% / 6.25%	6.00%	6.25%	5.50% / 6.25%	5.75%	6.25%
Expected long-term return on plan assets	8.25%	8.25%	8.50%	—	—	—
Rate of compensation increase	5.00%	4.00%	4.00%	—	—	—

*Not applicable due to change in method of accounting for defined benefit and other post retirement plans.

[1] The net periodic benefit cost was remeasured at May 1, 2006 using a discount rate of 6.25%, due to changes in plan provisions.

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. We assume the long-term asset mix will be consistent with a target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in the plan's asset allocation. Based on these factors we expect pension assets will earn an average of 8.25% per annum over the life of the plan.

In order to determine an appropriate discount rate at December 31, 2006, we performed an analysis of the Citigroup Pension Discount Curve (the "CPDC") as of that date for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities.

We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities. A 1% increase in the discount rate would have resulted in a decrease in net periodic benefit cost of $4 million in 2006. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of $5 million in 2006.

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

	2006	2005
Health care cost trend rate assumed for next year	10%	10%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5%	5%
Year rate reaches ultimate trend rate	2012	2011

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on total service and interest cost components for 2006	$ 530	$ (451)
Effect on year-end 2006 postretirement benefit obligation	2,460	(2,180)

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

	Target Allocation	Plan Assets	
	2007	2006	2005
Asset category			
Equity securities	70%	70%	73%
Fixed income	30%	28%	27%
Other	—	2%	—
Total	100%	100%	100%

The investment policy for the tax-qualified defined benefit pension plan is determined by an employee benefits committee ("the committee") with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet the immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. A 1% increase (decrease) in the expected return on plan assets would have resulted in a (decrease) increase, respectively, in net periodic benefit cost of $1 million in 2006.

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 December 31, 2006, we had cumulative asset gains of approximately $2 million, which remain to be recognized in the calculation of the market-related value of assets.

Contributions—We contributed cash of $36 million to the tax-qualified defined benefit pension, restoration and other postretirement benefit plans during 2006. We expect to make additional cash contributions of approximately $2 million during 2007 (unaudited).

Estimated Future Benefit Payments—As of December 31, 2006, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plan	Medical and Life Plan
	(in thousands)	
2007	$ 6,182	$ 941
2008	6,469	1,107
2009	6,788	1,297
2010	7,436	1,423
2011	8,244	1,918
Years 2012 to 2016	56,615	13,612

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2006 and includes estimated future employee service.

401(k) Plan—We sponsor a 401(k) savings plan. Participation is voluntary and all regular employees are eligible to participate. We make contributions to match employee contributions up to the first 6% of compensation deferred into the plan. In addition, we made a profit sharing contribution for all employees hired on or after May 1, 2006 based on the employee's age and salary. We made cash contributions of $4 million, $5 million and $2 million in 2006, 2005 and 2004, respectively.

Deferred Compensation Plan—In connection with the Patina Merger, we acquired the assets and assumed the liabilities related to a Patina shareholder-approved non-qualified deferred compensation plan ("Patina deferred compensation plan"). This plan was available to officers and certain managers of Patina and allowed participants to defer all or a portion of their salary and annual bonuses (either in cash or common stock). Participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants may elect to receive distributions in either cash or shares of Noble Energy common stock. We account for the deferred compensation plan in accordance with EITF 97-14, "Accounting for Deferred Compensation Arrangements Where Amounts Earned are Held in a Rabbi Trust and Invested." Components of the rabbi trust are as follows:

	December 31,	
	2006	2005
	(in thousands)	
Rabbi trust assets:		
Mutual fund investments	$ 100,767	$ 39,676
Noble Energy common stock (at market value)	54,027	87,410
Total rabbi trust assets	$ 154,794	$ 127,086
Liability under Patina deferred compensation plan	$ 154,794	$ 127,086
Number of shares of Noble Energy common stock held by rabbi trust	1,101,032	2,168,980

Assets of the rabbi trust, other than Noble Energy common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds are publicly quoted and reported at market value. We account for these investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The mutual funds are included in other noncurrent assets in the accompanying consolidated balance sheets. Noble Energy common stock held by the rabbi trust has been classified as treasury stock in the shareholders' equity section of the accompanying consolidated balance sheets. The amounts payable to the plan participants, including the market value of the shares of Noble Energy common stock that are reflected as treasury stock, are included in other noncurrent liabilities in the accompanying consolidated balance sheets. One million shares, or 91%, of the common stock held in the plan at December 31, 2006 and 2,060,000 shares or 95%, of the common stock held in the plan at December 31, 2005 were attributable to a member of our Board of Directors. Plan participants sold 1,067,948 shares of Noble Energy common stock during 2006 and 20,434 shares of Noble Energy common stock during 2005 and invested the proceeds in mutual funds. Distributions totaling $0.5 million and $1 million were made to Plan participants during 2006 and 2005, respectively.

In accordance with EITF 97-14, all fluctuations in market value of the rabbi trust assets have been reflected in the accompanying consolidated statements of operations. Increases or decreases in the value of the rabbi trust assets, exclusive of the shares of Noble Energy common stock, have been included in other expense, net in the accompanying consolidated statements of operations. This amount totaled $12 million during 2006 and $3 million during 2005. Increases or decreases in the market value of the deferred compensation liability, including the shares of Noble Energy common stock held by the rabbi trust, while recorded as treasury stock, are also included in other expense, net in the accompanying consolidated statements of operations. Based on the changes in the total market value of the rabbi trust assets, we recorded deferred compensation expense of $28 million during 2006 and $18 million during 2005.

Note 12—Derivative Instruments and Hedging Activities

Cash Flow Hedges—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. We account for derivative instruments and hedging activities in accordance with SFAS 133 and have elected to designate the majority of our derivative instruments as cash flow hedges.

Effects of cash flow hedges on oil and gas sales were as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Reduction of crude oil sales	$190,730	$140,486	$50,736
Reduction of natural gas sales	41,698	97,206	10,556
Total	$232,428	$237,692	$61,292

We recognized net ineffectiveness losses of $10 million in 2006 and $1 million in 2005. The net ineffectiveness loss in 2004 was de minimis.

If it becomes probable that the hedging instrument is no longer highly effective, the hedging instrument loses hedge accounting treatment. All current mark-to-market gains and losses are recorded in earnings and all accumulated gains or losses recorded in AOCL related to the hedging instrument are also reclassified to earnings. As a result of the impacts of Hurricanes Katrina and Rita on the timing of forecasted production during the fourth quarter of 2005, derivative instruments hedging approximately 6,000 barrels per day of crude oil and 40,000 MMBtu per day of natural gas no longer qualified for hedge accounting. Accordingly, beginning October 1, 2005 the changes in fair value of these derivative contracts were recognized in our results of operations, causing a mark-to-market gain of $20 million in 2005. In addition, the delay in the timing of production resulted in a loss of $52 million in fourth quarter 2005 related to amounts previously recorded in AOCL. In first quarter 2006, the changes in fair value of these derivative contracts caused a mark-to-market gain of $39 million, and the delay in the timing of our production resulted in a loss of $25 million related to amounts previously recorded in AOCL. These gains and losses are included in loss on derivative instruments in the consolidated statements of operations. These derivative instruments were redesignated as cash flow hedges in February 2006.

We have hedging instruments that were designated as cash flow hedges of production from our Gulf of Mexico shelf properties. We sold these shelf properties during the third quarter 2006. During the second quarter 2006, when it became probable that forecasted production would not occur due to the pending sale, we determined that deferral of losses in AOCL related to this forecasted production was no longer appropriate under SFAS 133. As a result, we reclassified a pretax charge of $399 million related to the cash flow hedges from AOCL to earnings. This amount is included in loss on derivative instruments in the consolidated statements of operations. We redesignated the majority of these instruments as cash flow hedges for other North America production. Future earnings will reflect only those changes in derivative fair value that occur after the date of redesignation and are deferred in AOCL until the forecasted production occurs. In addition, a mark-to-market gain of $3 million relating to a hedging instrument that was not redesignated is included in loss on derivative instruments during 2006.

No gains or losses were reclassified from AOCL into earnings as a result of the discontinuance of hedge accounting treatment during 2004.

At December 31, 2006, we had entered into future costless collar transactions related to crude oil and natural gas production as follows:

	Natural Gas			Crude Oil		
		Average price per MMBtu			Average price per Bbl	
Production Period	MMBtupd	Floor	Ceiling	Bopd	Floor	Ceiling
2007 (NYMEX)	—	—	—	2,700	$60.00	$74.30
2007 (CIG) [1]	12,000	$6.50	$9.50	—	—	—
2007 (Brent)	—	—	—	6,748	45.00	70.63
2008 (NYMEX)	—	—	—	3,100	60.00	72.40
2008 (CIG)	14,000	6.75	8.70	—	—	—
2008 (Brent)	—	—	—	4,074	45.00	66.52
2009 (NYMEX)	—	—	—	3,700	60.00	70.00
2009 (CIG)	15,000	6.00	9.90	—	—	—
2009 (Brent)	—	—	—	3,074	45.00	63.05
2010 (NYMEX)	—	—	—	3,500	55.00	73.80
2010 (CIG)	15,000	6.25	8.10	—	—	—

[1] Colorado Interstate Gas

At December 31, 2006, we had entered into future fixed price swap transactions related to crude oil and natural gas production as follows:

	Natural Gas		Crude Oil	
Production Period	MMBtupd	Average Price per MMBtu	Bopd	Average price per Bbl
2007 (NYMEX)	170,000[1]	$6.04	17,100	$39.19
2008 (NYMEX)	170,000[1]	5.67	16,500	38.23

[1] Includes fixed price swaps of 140,000 MMBtupd of natural gas for 2007 and 150,000 MMBtupd of natural gas for 2008 for which cash flow hedge accounting was discontinued at June 30, 2006 due to the pending sale of Gulf of Mexico shelf properties. These swaps (with associated basis swaps) were redesignated as cash flow hedges in the second quarter 2006.

At December 31, 2006, we had entered into basis swap transactions related to natural gas production. These basis swaps have been combined with NYMEX commodity swaps and designated as cash flow hedges. The basis swaps are as follows:

	Natural Gas	
Production Period	MMBtupd	Average Differential per MMBtu
2007 (CIG vs. NYMEX)	100,000	$2.02
2007 (ANR [1] vs. NYMEX)	30,000	1.17
2007 (PEPL [2] vs. NYMEX)	10,000	1.11
2008 (CIG vs. NYMEX)	100,000	1.66
2008 (ANR vs. NYMEX)	40,000	1.01
2008 (PEPL vs. NYMEX)	10,000	0.98

(1) ANR Pipeline
(2) Panhandle Eastern Pipe Line

The costless collar, fixed price swap and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed price or floor price. We would pay the counterparty if the settlement price for the scheduled trading day applicable for each calculation period is more than the fixed price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess, if any, of the fixed or floor price over the floating price in respect of each calculation period.

Accumulated Other Comprehensive Loss—As of December 31, 2006 and 2005, the balance in AOCL included net deferred losses of $104 million and $764 million, respectively, related to the fair value of crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefit of $63 million and $411 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2006, approximately $21 million of deferred losses, net of tax, related to the fair values of crude oil and natural gas derivative instruments included in AOCL at December 31, 2006 would be reclassified to earnings during the next twelve months as the forecasted transactions occur, and would be recorded as a reduction in oil and gas sales of approximately $34 million before tax. Any actual increase or decrease in revenues will depend upon market conditions over the period during which the forecasted transactions occur. All current crude oil and natural gas derivative instruments, except those described in the following paragraph, are designated as cash flow hedges. All forecasted transactions currently being hedged are expected to occur by December 2010.

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

Derivative instruments used in connection with purchases and sales of third-party production are reflected at fair value as either assets or liabilities in the consolidated balance sheets. We record gains and losses on derivative instruments using mark-to-market accounting. Under this accounting method, the changes in the market value of outstanding derivative instruments are recognized as gains or losses in the period of change. Gains and losses related to changes in fair value are included in gathering, marketing and processing revenues. We recorded a net gain of $1 million during 2006 and a net loss of $2 million during 2005 related to derivative instruments. Net gains and losses for 2004 were de minimis.

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

	December 31,	
	2006	2005
	(in thousands)	
Derivative instruments (current asset)	$ 35,242	$ 29,258
Derivative instruments (long-term asset)	2,862	17,259
Derivative instruments (current liability)	(254,625)	(445,939)
Derivative instruments (long-term liability)	(328,875)	(757,509)

Interest Rate Lock—We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. At December 31, 2006, AOCL included a deferred loss of $3 million, net of tax, related to an interest rate swap which was settled in 2004. This amount is being reclassified into earnings as adjustments to interest expense over the term of the 5¼% senior notes due 2014. At December 31, 2005, the amount of deferred loss included in AOCL was $4 million, net of tax. The amounts amortized to interest expense were $0.8 million, $0.8 million and $0.5 million for the years ending December 31, 2006, 2005 and 2004, respectively.

Note 13—Equity Method Investments

Investments accounted for under the equity method consist primarily of the following:

- 45% interest in Atlantic Methanol Production Company, LLC ("AMPCO, LLC"), which owns and operates a methanol production facility and related facilities in Equatorial Guinea; and
- 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant.

Construction of the Alba Plant was funded primarily through advances by Noble Energy and other owners in exchange for notes payable by the Alba Plant. The notes were scheduled to mature on December 31, 2011 and bore interest at the 90-day LIBOR rate plus 3%. The notes were repaid in 2006. Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investments in the consolidated statements of operations. The carrying value of our equity method investments is $14 million higher than the underlying net assets of the investees. This basis difference is being amortized into income over the remaining useful lives of the underlying net assets.

Equity method investments are as follows:

	2006	2005
	(in thousands)	
Equity method investments:		
Atlantic Methanol Production Company, LLC	$211,325	$214,226
Alba Plant LLC	146,051	195,109
Other	15,996	11,027
Total equity method investments	$373,372	$420,362

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

	December 31,	
	2006	2005
	(in thousands)	
Balance Sheet Information		
Current assets	$252,201	$274,484
Noncurrent assets	857,465	877,402
Current liabilities	171,028	119,912
Noncurrent liabilities	2,385	450,156

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Statements of Operations Information			
Operating revenues	$702,556	$464,000	$263,256
Less cost of goods sold	202,304	136,508	104,987
Gross margin	500,252	327,492	158,269
Less other expense (income)	47,487	35,798	(21,161)
Less income tax expense (benefit)	23,451	67,142	(5,597)
Net income	$429,314	$224,552	$185,027

Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investments and is not included in our income tax provision in the consolidated statements of operations. At December 31, 2006, retained earnings included $144 million related to the undistributed earnings of equity method investees.

Note 14—Commitments and Contingencies

Legal Proceedings—The ruling by the Colorado Supreme Court in *Rogers v. Westerman Farm Co.* in July 2001 resulted in uncertainty regarding the deductibility of certain post-production costs from payments to be made to royalty interest owners. In January 2003, Patina was named as a defendant in a lawsuit, which plaintiff sought to certify as a class action, based upon the *Rogers* ruling alleging that Patina had improperly deducted certain costs in connection with its calculation of royalty payments relating to its Wattenberg field operations and seeking monetary damages *(Jack Holman, et al v. Patina Oil & Gas Corporation; Case No. 03-CV-09; District Court, Weld County, Colorado)*. In May 2004, the plaintiff filed an amended complaint narrowing the class of potential plaintiffs, and thereafter filed a motion seeking to certify the narrowed class as described in the amended complaint. Patina filed an answer to the amended complaint. A motion seeking class certification was heard on September 22, 2005 and granted on October 13, 2005. The Colorado Supreme Court denied our petition for review on November 23, 2005.

The matter was set for trial scheduled to commence April 24, 2007. In October 2006, we received service in an additional lawsuit styled *Wardell Family Partnership and Glen Droegemueller v. Noble Energy, Inc. et al; Case No. 06-CV-734, District Court, Weld County, Colorado,* involving royalty and overriding royalty interest owners in the same field and not a member of the *Holman* class. The plaintiffs sought to certify the lawsuit as a class action and allegations were made of a similar nature as the *Holman* lawsuit. An answer was timely filed. Through a mediation process, we and the attorneys representing the *Holman* class and *Wardell* putative class have entered into an agreement in principle to settle both cases, and the April 24, 2007 trial date in the *Holman* lawsuit has been vacated. Such a settlement will have to be approved by the Court with notice of the settlement going to all members of the *Holman* class and *Wardell* putative class.

The Illinois Environmental Protection Agency (IEPA) issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. Elysium Energy, LLC acquired Equinox, and Elysium subsequently was acquired by Patina. The facility is a small amine-processing unit used to treat and remove hydrogen sulfide from natural gas prior to transportation. The notice of violation alleges violation of permit requirements under the Clean Air Act dating back to 1986 as well as excessive hydrogen sulfide emissions at the plant. We are cooperatively working with the IEPA staff to address this matter and have received a permit to allow the installation of remediation equipment. On January 17, 2007, the IEPA re-issued written notices of these alleged violations in the name of Equinox's successors in interest, and our subsidiaries, Elysium and Noble Energy Production, Inc. No action will be pursued against Equinox. On February 12, 2007, a compliance commitment agreement was submitted to the IEPA wherein Noble Energy Production and Elysium have agreed to pay a late permit fee, install an incineration/caustic scrubber emissions control system at the site, and fund a supplemental environmental project in the nearby community. The matter will remain open until the emissions control system is constructed and operating within IEPA parameters, which is not expected to occur until the third quarter of 2007.

We are involved in various legal proceedings, including the foregoing matters, in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. The company is defending itself vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Non-Cancelable Leases and Other Commitments—We hold leases and other commitments for drilling rigs, buildings, equipment and other properties. Net rental expense was approximately $12 million, $10 million and $7 million for 2006, 2005 and 2004, respectively.

Net minimum commitments as of December 31, 2006 consist of the following:

	Net Minimum Commitments			
	Drilling Rig and Equipment Contracts	Building Leases	Equipment Leases	Total
	(in thousands)			
2007	$328,987	$10,237	$5,168	$344,392
2008	161,820	6,159	1,142	169,121
2009	58,399	6,018	477	64,894
2010	71,966	5,878	—	77,844
2011	65,490	5,690	—	71,180
2012 and thereafter	61,950	17,985	—	79,935
Total	$748,612	$51,967	$6,787	$807,366

In January 2007, we entered into a five-year throughput and deficiency agreement with a financial commitment of $95 million. The transporting pipeline, the construction of which is subject to regulatory approval, is expected to be completed and operational in 2009.

Note 15—Geographical Data

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of natural gas and crude oil exploration and production: U.S.; West Africa (Equatorial Guinea and Cameroon); North Sea; Israel; and Other International, Corporate and Marketing. Other International includes Argentina, China, Ecuador and Suriname.

Accounting policies for geographical segments are the same as those described in the summary of significant accounting policies. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments.

	Total	United States	West Africa	North Sea	Israel	Other Int'l, Corporate & Marketing
			(in thousands)			
Year Ended December 31, 2006						
Revenues from third parties	$2,800,720	$1,510,689	$413,682	$115,232	$ 92,373	$ 668,744
Intersegment revenue	—	425,901	—	—	—	(425,901)
Income from equity method investments	139,362	—	139,362	—	—	—
Total Revenues	2,940,082	1,936,590	553,044	115,232	92,373	242,843
DD&A	622,608	543,431	23,620	8,123	13,947	33,487
Loss on derivative instruments	392,367	392,367	—	—	—	—
Impairment of operating assets	8,525	8,525	—	—	—	—
Income from continuing operations before tax	1,096,217	631,087	493,777	72,803	71,318	(172,768)
Investments in equity method investees	373,372	—	373,372	—	—	—
Additions to long-lived assets	1,916,139	1,615,435	35,121	234,877	841	29,865
Total assets at December 31, 2006 (1)	9,588,625	7,224,920	960,357	343,236	256,913	803,199
Year Ended December 31, 2005						
Revenues from third parties	$2,095,911	$ 913,564	$281,902	$123,584	$ 65,050	$ 711,811
Intersegment revenue	—	460,808	—	—	—	(460,808)
Income from equity method investments	90,812	—	90,812	—	—	—
Total Revenues	2,186,723	1,374,372	372,714	123,584	65,050	251,003
DD&A	390,544	311,153	27,121	9,888	11,188	31,194
Loss on derivative instruments	32,680	32,680	—	—	—	—
Impairment of operating assets	5,368	5,368	—	—	—	—
Income from continuing operations before tax	968,660	585,988	309,239	88,524	46,468	(61,559)
Investments in equity method investees	420,362	—	420,362	—	—	—
Additions to long-lived assets	4,382,005	4,345,604	2,738	15,287	5,928	12,448
Total assets at December 31, 2005 (2)	8,878,033	6,577,853	877,409	146,311	266,312	1,010,148
Year Ended December 31, 2004						
Revenues from third parties	$1,272,852	$ 335,329	$132,590	$115,181	$ 48,855	$ 640,897
Intersegment revenue	—	455,068	—	—	—	(455,068)
Income from equity method investments	78,199	—	78,199	—	—	—
Total Revenues	1,351,051	790,397	210,789	115,181	48,855	185,829
DD&A	308,103	240,058	13,925	18,244	9,058	26,818
Loss on derivative instruments	272	272	—	—	—	—
Impairment of operating assets	9,885	9,885	—	—	—	—
Income from continuing operations before tax	513,008	294,412	162,576	70,305	32,088	(46,373)
Investments in equity method investees	377,384	—	377,384	—	—	—
Additions to long-lived assets	469,445	280,280	114,188	10,795	(8,313)	72,495
Total assets at December 31, 2004	3,435,784	1,299,547	809,675	218,881	273,347	834,334

(1) The domestic reporting unit includes goodwill of $781 million.

(2) The domestic reporting unit includes goodwill of $863 million.

Note 16—Discontinued Operations

During 2004, we completed an asset divestiture program that had first been announced during July 2003. The asset divestiture program included five domestic property packages. The sales price for the five property packages totaled $130 million. Pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," our consolidated financial statements were reclassified for all periods previously presented to reflect the operations and assets of the properties being sold as discontinued operations. The net income from discontinued operations was classified in the consolidated statements of operations as "Discontinued Operations, Net of Tax."

Summarized results of discontinued operations are as follows:

	Year ended December 31, 2004
	(in thousands)
Oil and gas sales and royalties	$12,575
Realized gain	14,996
Income before income taxes	22,862

Long-term debt is recorded at the consolidated level and is not allocated to components. Therefore, no interest expense was allocated to the discontinued operations.

Note 17—Recently Issued Pronouncements

SFAS 155—In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" ("SFAS 155"). SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This Statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We adopted SFAS 155 as of January 1, 2007. Adoption had no effect on our financial position or results of operations.

SFAS 157—Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS 157"), establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. SFAS 157 is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We adopted SFAS 157 as of January 1, 2007. Adoption had no effect on our financial position or results of operations.

SFAS 159—In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We are currently evaluating the provisions of SFAS 159 and assessing the impact it may have on our financial position and results of operations.

FASB Staff Position AUG AIR-1—FASB Staff Position No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities" ("FSP AUG AIR-1"), prohibits companies from accruing as a liability in annual and interim periods the future costs of periodic major overhauls and maintenance of plant and equipment (the "accrue-in-advance method"). Other previously acceptable methods of accounting for planned major overhauls and maintenance (the direct expense, built-in overhaul and deferral methods) will continue to be permitted. The new requirements apply to entities in all industries for fiscal years beginning after December 15, 2006, and must be retrospectively applied. We adopted FSP AUG AIR-1 as of January 1, 2007. Adoption had no effect on our financial position or results of operations.

FIN 48—In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109", ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We adopted FIN 48 effective January 1, 2007. However, the FASB is in the process of issuing Proposed FSP FIN 48-a, "Implementation Guidance on Interpretation 48". The guidance will provide conditions for determining when a tax position is considered to be effectively settled through examination. Although the final amount of our adoption adjustment will depend on the guidance issued, we do not expect the final impact of adoption to have a material effect on our financial position.

Supplemental Oil and Gas Information (Unaudited)

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

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Engineers in our Houston and Denver offices perform 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 Senior Vice President with responsibility for corporate reserves. During each of the years 2006, 2005 and 2004, we retained Netherland, Sewell & Associates, Inc. ("NSAI"), independent third-party reserve engineers, to perform reserve audits of proved reserves. The reserve audit for 2006 included a detailed review of 14 of our major international, deepwater and domestic properties, 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 and domestic properties, which covered approximately 72% of our total proved reserves. The reserve audit for 2004 included a detailed review of 11 of our major international, deepwater and domestic properties, which covered approximately 78% of our total proved reserves. See Items 1 and 2. Business and Properties—Proved Reserves.

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

Our supplemental disclosures are grouped by geographic area and include the U.S., West Africa (Equatorial Guinea and Cameroon), Israel, Ecuador, North Sea, China, Argentina and Other International. Operations in Equatorial Guinea, Cameroon, Ecuador and China are conducted in accordance with the terms of production sharing contracts.

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

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

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

The following definitions apply to our categories of proved reserves:

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

Proved Developed Reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Undeveloped Reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved Gas Reserves (Unaudited)

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

	Natural Gas and Casinghead Gas (MMcf)						
	United States	West Africa	Israel	Ecuador	North Sea	Argentina	Total
Proved reserves as of:							
December 31, 2003	558,058	537,998	450,307	79,298	13,811	2,448	1,641,920
Revisions of previous estimates [1]	(7,452)	(4,130)	(15,441)	(27,398)	1,552	(937)	(53,806)
Extensions, discoveries and other additions [1][2]	74,277	400,288	—	75,081	685	—	550,331
Purchase of minerals in place	14,437	—	—	—	—	—	14,437
Sale of minerals in place	(30,127)	—	—	—	(204)	—	(30,331)
Production	(89,458)	(16,747)	(17,573)	(7,640)	(4,130)	(142)	(135,690)
December 31, 2004	519,735	917,409	417,293	119,341	11,714	1,369	1,986,861
Revisions of previous estimates [3]	18,644	7,732	481	32,800	3,200	(1,301)	61,556
Extensions, discoveries and other additions [4]	144,335	—	—	—	—	—	144,335
Purchase of minerals in place [5]	1,083,959	—	—	—	—	—	1,083,959
Sale of minerals in place	—	—	—	—	—	—	—
Production	(125,543)	(23,938)	(24,228)	(8,321)	(3,394)	(68)	(185,492)
December 31, 2005	1,641,130	901,203	393,546	143,820	11,520	—	3,091,219
Revisions of previous estimates [6]	(82,371)	57,543	260	32,927	10,485	278	19,122
Extensions, discoveries and other additions [7]	314,140	—	—		—		314,140
Purchase of minerals in place [8]	141,610	2,532	—	—	—	—	144,142
Sale of minerals in place [9]	(110,486)	—	—	—	—	—	(110,486)
Production	(164,830)	(16,579)	(33,906)	(8,933)	(2,967)	(108)	(227,323)
December 31, 2006	1,739,193	944,699	359,900	167,814	19,038	170	3,230,814
Proved developed reserves as of:							
December 31, 2003	506,457	462,474	378,001	25,130	13,811	2,197	1,388,070
December 31, 2004	430,513	447,347	360,428	119,341	11,714	1,118	1,370,461
December 31, 2005	1,278,788	431,142	336,681	143,820	11,520	—	2,201,951
December 31, 2006	1,255,271	359,691	303,035	167,814	19,038	170	2,105,019

(1) Ecuador revisions and discoveries are due to additional drilling.

(2) In 2004, we entered into an additional natural gas contract with an LNG plant in Equatorial Guinea. We increased reserves based on minimum contractual volumes required to be taken under this agreement.

(3) Increases for Ecuador are due to better than expected performance.

(4) The increase in domestic proved reserves includes 57 Bcf in the Wattenberg field and 40 Bcf in the western Mid-continent area.

(5) Purchase of minerals in place is the result of the Patina Merger. See Note 3—Acquisitions and Divestitures.

(6) Increases for Ecuador and North Sea are due to better than expected performance.

(7) The increase in domestic proved reserves includes 140 Bcf in the Wattenberg field, 77 Bcf in the Piceance Basin and 55 Bcf in the western Mid-continent area.

(8) Purchase of minerals in place includes 128 Bcf acquired in the purchase of U.S. Exploration. See Note 3—Acquisitions and Divestitures.

(9) Sale of minerals in place is primarily due to sale of Gulf of Mexico shelf properties. See Note 3—Acquisitions and Divestitures.

Proved Oil Reserves (Unaudited)

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

	Crude Oil and Condensate (MBbls)					
	United States	West Africa	North Sea	China	Argentina	Total
Proved reserves as of:						
December 31, 2003	42,304	113,198	8,460	10,336	8,921	183,219
Revisions of previous estimates	976	(1,104)	1,037	(1,438)	1,995	1,466
Extensions, discoveries and other additions [1]	16,760	—	4,414	3,024	—	24,198
Purchase of minerals in place	5,289	—	—	—	—	5,289
Sale of minerals in place	(2,190)	—	(2,116)	—	—	(4,306)
Production	(8,073)	(3,364)	(2,459)	(1,421)	(1,085)	(16,402)
December 31, 2004	55,066	108,730	9,336	10,501	9,831	193,464
Revisions of previous estimates	4,192	(1,303)	278	15	153	3,335
Extensions, discoveries and other additions [2]	11,272	—	12,955	—	—	24,227
Purchase of minerals in place [3]	90,594	—	—	—	—	90,594
Sale of minerals in place	—	—	—	—	—	—
Production	(9,468)	(6,492)	(1,964)	(1,807)	(1,059)	(20,790)
December 31, 2005	151,656	100,935	20,605	8,709	8,925	290,830
Revisions of previous estimates	(193)	(4,258)	(396)	12	112	(4,723)
Extensions, discoveries and other additions [4]	23,037	—	—	1,794	—	24,831
Purchase of minerals in place [5]	19,328	138	—	—	—	19,466
Sale of minerals in place [6]	(6,971)	—	—	—	—	(6,971)
Production	(16,715)	(6,519)	(1,357)	(1,539)	(1,213)	(27,343)
December 31, 2006	170,142	90,296	18,852	8,976	7,824	296,090
Proved developed reserves as of:						
December 31, 2003	34,246	113,198	8,460	10,336	8,004	174,244
December 31, 2004	32,390	108,730	9,336	10,501	7,539	168,496
December 31, 2005	114,223	100,935	7,650	8,709	6,914	238,431
December 31, 2006	114,505	90,296	18,852	8,976	6,960	239,589

(1) The increase in domestic proved reserves includes 14 MMBbl in the deepwater Gulf of Mexico Ticonderoga field.

(2) The increase in total proved reserves includes 6 MMBbl in the Wattenberg field, 3 MMBbl in the deepwater Gulf of Mexico Lorien field and 13 MMBbl in the North Sea Dumbarton field.

(3) Purchase of minerals in place is the result of the Patina Merger. See Note 3—Acquisitions and Divestitures.

(4) The increase in domestic proved reserves includes 14 MMBbl in the Wattenberg field.

(5) Purchase of minerals in place includes 18 MMBbl acquired in the purchase of U.S. Exploration. See Note 3—Acquisitions and Divestitures.

(6) Sale of minerals in place is primarily due to the sale of Gulf of Mexico shelf properties. See Note 3—Acquisitions and Divestitures.

Results of Operations for Oil and Gas Producing Activities (Unaudited)

Aggregate results of continuing operations in connection with crude oil and natural gas producing activities are as follows:

	United States	West Africa	Israel	Ecuador	North Sea	China	Argentina	Other Int'l	Total
					(in thousands)				
Year Ended December 31, 2006									
Revenues	$1,936,590	$413,682	$92,373	$33,575	$115,232	$85,913	$57,451	$ —	$2,734,816
Production costs [1]	338,655	26,556	9,066	3,021	11,655	17,336	22,260	—	428,549
Transportation	20,729	—	—	—	7,010	803	—	—	28,542
E&P corporate	60,710	4,656	111	3,102	3,346	250	699	1,169	74,043
Exploration expenses	113,015	7,329	286	228	10,499	(227)	584	10,954	142,668
DD&A	561,948	23,402	13,911	11,611	8,045	11,617	14,068	—	644,602
Impairment of operating assets	8,525	—	—	—	—	—	—	—	8,525
Accretion expense	8,861	104	452	221	1,159	—	—	—	10,797
Income before income taxes	824,147	351,635	68,547	15,392	73,518	56,134	19,840	(12,123)	1,397,090
Income tax expense	313,011	125,493	19,810	3,848	42,111	18,524	6,944	(2,100)	527,641
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 511,136	$226,142	$48,737	$11,544	$ 31,407	$37,610	$12,896	$(10,023)	$ 869,449
Company's share of Alba Plant LLC's results of operations from producing activities	$ —	$101,338	$ —	$ —	$ —	$ —	$ —	$ —	$ 101,338
Year Ended December 31, 2005									
Revenues	$1,374,374	$281,901	$65,050	$31,868	$123,583	$85,352	$36,162	$ —	$1,998,290
Production costs [1]	216,478	30,659	8,504	3,000	12,503	12,502	16,294	—	299,940
Transportation	9,350	—	—	—	6,562	910	(58)	—	16,764
E&P corporate	34,162	435	188	2,611	2,591	567	120	260	40,934
Exploration expenses	130,018	5,463	223	341	5,985	(142)	1,606	11,216	154,710
DD&A	328,645	26,978	11,120	12,246	9,866	13,115	11,122	—	413,092
Impairment of operating assets	5,368	—	—	—	—	—	—	—	5,368
Accretion expense	9,590	51	281	158	1,134	—	—	—	11,214
Income before income taxes	640,763	218,315	44,734	13,512	84,942	58,400	7,078	(11,476)	1,056,268
Income tax expense	140,916	76,518	7,752	3,378	36,834	19,272	2,478	(717)	286,431
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 499,847	$141,797	$36,982	$10,134	$ 48,108	$39,128	$ 4,600	$(10,759)	$ 769,837
Company's share of Alba Plant LLC's results of operations from producing activities	$ —	$ 33,916	$ —	$ —	$ —	$ —	$ —	$ —	$ 33,916
Year Ended December 31, 2004									
Revenues	$ 790,397	$132,590	$48,855	$24,043	$115,181	$45,398	$32,554	$ —	$1,189,018
Production costs [1]	125,018	20,811	7,203	2,184	8,803	10,119	11,407	—	185,545
Transportation	8,631	—	—	—	10,480	697	—	—	19,808
E&P corporate	15,599	596	163	2,750	2,302	—	—	(77)	21,333
Exploration expenses	73,971	7,214	598	239	11,115	265	1,325	981	95,708
DD&A	259,365	13,925	9,549	15,338	18,215	10,466	10,263	—	337,121
Impairment of operating assets	9,885	—	—	—	—	—	—	—	9,885
Accretion expense	8,021	6	163	—	1,140	—	—	—	9,330
Income (loss) before income taxes	289,907	90,038	31,179	3,532	63,126	23,851	9,559	(904)	510,288
Income tax expense	106,603	46,011	9,896	1,810	28,542	4,012	5,763	(330)	202,307
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 183,304	$ 44,027	$21,283	$ 1,722	$ 34,584	$19,839	$ 3,796	$ (574)	$ 307,981
Company's share of Alba Plant LLC's results of operations from producing activities	$ —	$ 9,099	$ —	$ —	$ —	$ —	$ —	$ —	$ 9,099

[1] Production costs consist of oil and gas operations expense, production and ad valorem taxes, plus general and administrative expense supporting oil and gas operations.

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

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

	United States	West Africa	Israel	Ecuador	North Sea	China	Argentina	Other Int'l	Total
					(in thousands)				
Year Ended December 31, 2006									
Property acquisition costs									
Proved [2]	$ 514,294	$ 7,971	$ —	$ —	$ —	$ —	$ —	$ —	$ 522,265
Unproved [2]	157,141	25,500	1,000	—	831	—	—	—	184,472
Total acquisition costs	671,435	33,471	1,000	—	831	—	—	—	706,737
Exploration costs	204,787	13,076	286	228	18,185	(227)	584	10,954	247,873
Development costs [3][4]	784,877	6,933	13,869	48	231,484	7,590	14,059	—	1,058,860
Total consolidated operations	$1,661,099	$ 53,480	$15,155	$ 276	$250,500	$ 7,363	$14,643	$10,954	$2,013,470
Company's share of Alba Plant LLC's development costs	$ —	$ 580	$ —	$ —	$ —	$ —	$ —	$ —	$ 580
Year Ended December 31, 2005									
Property acquisition costs									
Proved [2]	$2,642,572	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$2,642,572
Unproved [2]	1,084,545	—	—	—	140	—	—	250	1,084,935
Total acquisition costs	3,727,117	—	—	—	140	—	—	250	3,727,507
Exploration costs	164,820	18,126	223	341	6,308	(142)	1,606	11,216	202,498
Development costs [3][4][5]	657,858	2,738	5,928	(1,660)	19,729	2,980	11,249	(371)	698,451
Total consolidated operations	$4,549,795	$ 20,864	$ 6,151	$ (1,319)	$ 26,177	$ 2,838	$12,855	$11,095	$4,628,456
Company's share of Alba Plant LLC's development costs	$ —	$ 27,639	$ —	$ —	$ —	$ —	$ —	$ —	$ 27,639
Year Ended December 31, 2004									
Property acquisition costs									
Proved	$ 85,785	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 85,785
Unproved	25,547	14,459		—	4,651	—	24	—	44,681
Total acquisition costs	111,332	14,459	—	—	4,651	—	24	—	130,466
Exploration costs	106,985	7,214	598	239	12,256	265	1,325	981	129,863
Development costs [3][4][5]	174,179	100,155	(5,887)	50,727	9,509	12,412	10,324	576	351,995
Total consolidated operations	$ 392,496	$121,828	$ (5,289)	$50,966	$ 26,416	$12,677	$11,673	$ 1,557	$ 612,324
Company's share of Alba Plant LLC's development costs	$ —	$ 61,498	$ —	$ —	$ —	$ —	$ —	$ —	$ 61,498

(1) Costs incurred include capitalized and expensed items.

(2) Includes amounts allocated from the U.S. Exploration acquisition (2006) and the Patina Merger (2005). See Note 3—Acquisitions and Divestitures.

(3) U.S. development costs include $4 million, $39 million and $5 million related to asset retirement obligations in 2006, 2005 and 2004 respectively. U.S. asset retirement costs of $33 million in 2006, $66 million in 2005, and $130 million in 2004 were incurred as a result of hurricane damage and are excluded from the costs incurred schedule above as we expect to recover the costs from insurance proceeds. See Note 4—Effect of Gulf Coast Hurricanes.

(4) Worldwide development costs include $768 million, $471 million and $179 million spent to develop proved undeveloped reserves in 2006, 2005, and 2004, respectively. Worldwide development costs also include $191 million spent on a floating production, storage and offloading vessel in the Dumbarton field in 2006.

(5) North Sea development costs include $5 million and $3 million related to asset retirement obligations in 2005 and 2004 respectively.

Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited)

Aggregate capitalized costs relating to crude oil and natural gas producing activities, including asset retirement costs and related accumulated DD&A, are as follows:

	December 31,	
	2006	2005
	(in thousands)	
Unproved oil and gas properties	$ 972,895	$ 1,066,888
Proved oil and gas properties [1]	7,886,079	7,335,188
Total oil and gas properties	8,858,974	8,402,076
Accumulated DD&A	(1,725,431)	(2,239,596)
Net capitalized costs	$ 7,133,543	$ 6,162,480
Company's share of Alba Plant LLC's net capitalized costs	$ 124,454	$ 134,067

[1] Proved oil and gas properties at December 31, 2006 and 2005 include asset retirement costs of $49 million and $131 million, respectively.

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

The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2006, 2005 and 2004 in accordance with SFAS 69. The standard requires the use of a 10% discount rate. This information is not the fair market value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves:

	United States	West Africa	Israel	Ecuador	North Sea	China	Argentina	Total
				(in millions)				
December 31, 2006								
Future cash inflows [1]	$18,948	$4,904	$ 972	$629	$1,225	$460	$348	$27,486
Future production costs [2]	4,551	738	146	162	327	117	70	6,111
Future development costs	2,846	80	90	12	35	3	25	3,091
Future income tax expenses	3,422	1,348	187	130	435	103	74	5,699
Future net cash flows	8,129	2,738	549	325	428	237	179	12,585
10% annual discount forestimated timing of cash flows	3,966	1,132	215	170	95	65	55	5,698
Standardized measure ofdiscounted future netcash flows	$ 4,163	$1,606	$ 334	$155	$ 333	$172	$124	$ 6,887
December 31, 2005								
Future cash inflows [1]	$22,931	$5,436	$1,031	$539	$1,267	$453	$415	$32,072
Future production costs [2]	5,099	556	154	47	352	118	172	6,498
Future development costs	1,887	92	88	12	184	3	34	2,300
Future income tax expenses	4,645	1,589	182	142	381	101	58	7,098
Future net cash flows	11,300	3,199	607	338	350	231	151	16,176
10% annual discount forestimated timing of cash flows	5,201	1,554	236	162	138	60	54	7,405
Standardized measure ofdiscounted future netcash flows	$ 6,099	$1,645	$ 371	$176	$ 212	$171	$ 97	$ 8,771
December 31, 2004								
Future cash inflows [1]	$ 5,429	$4,358	$1,089	$377	$ 439	$362	$300	$12,354
Future production costs [2]	1,135	490	133	42	153	131	179	2,263
Future development costs	364	83	88	16	23	3	30	607
Future income tax expenses	1,219	1,704	264	129	109	64	29	3,518
Future net cash flows	2,711	2,081	604	190	154	164	62	5,966
10% annual discount forestimated timing of cash flows	1,104	1,079	249	82	33	53	24	2,624
Standardized measure ofdiscounted future netcash flows	$ 1,607	$1,002	$ 355	$108	$ 121	$111	$ 38	$ 3,342

(1) The standardized measure of discounted future net cash flows for 2006, 2005 and 2004 does not include cash flows relating to anticipated future methanol or power sales.

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

Future cash inflows are computed by applying year-end prices, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	West Africa	Israel	Ecuador	North Sea	China	Argentina	Total
December 31, 2006								
Average crude oil price per Bbl	$57.02	$51.49	$ —	$ —	$57.81	$51.25	$44.35	$54.87
Average natural gas price per Mcf	5.32	0.27	2.70	3.75	7.11	—	0.85	3.48
December 31, 2005								
Average crude oil price per Bbl	$58.20	$51.62	$ —	$ —	$58.47	$52.01	$46.51	$55.39
Average natural gas price per Mcf	8.59	0.25	2.62	3.75	5.39	—	—	5.16
December 31, 2004								
Average crude oil price per Bbl	$41.25	$37.97	$ —	$ —	$40.93	$34.45	$30.45	$38.48
Average natural gas price per Mcf	6.07	0.25	2.61	3.16	4.84	—	0.84	2.47

We estimate that a $1.00 per Bbl change or a $.10 per Mcf change in the average crude oil price or the average natural gas price, respectively, from the year-end price at December 31, 2006 would change the discounted future net cash flows before income taxes by approximately $162 million or $153 million, respectively.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future development costs include $922 million, $556 million and $501 million that we expect to spend in 2007, 2008 and 2009, respectively, to develop proved undeveloped reserves.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved crude oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax credits and allowances, but do not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

Imbalance receivables and liabilities are as follows:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Imbalance receivables	$18,389	$18,100	$21,200
Imbalance liabilities	16,750	34,600	16,100

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

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

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

	Year ended December 31,		
	2006	2005	2004
	(in millions)		
Standardized measure of discounted future netcash flows at the beginning of the year	$ 8,771	$ 3,342	$ 2,512
Sales of oil and gas produced, net of production costs	(2,177)	(1,563)	(1,014)
Net changes in prices and production costs	(2,788)	2,160	861
Extensions, discoveries and improved recovery, less related costs	769	1,173	839
Changes in estimated future development costs	(558)	(912)	99
Development costs incurred during the period	1,076	751	92
Revisions of previous quantity estimates	(92)	273	(70)
Purchases of minerals in place	573	4,720	219
Sales of minerals in place	(579)	—	(207)
Accretion of discount	1,274	519	406
Net change in income taxes	777	(2,099)	(380)
Change in timing of estimated future production and other	(159)	407	(15)
Aggregate change in standardized measure of discounted future net cash flows	(1,884)	5,429	830
Standardized measure of discounted future net cash flows at the end of the year	$ 6,887	$ 8,771	$ 3,342

Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended			
	Mar. 31,	June 30,	Sept. 30,	Dec. 31,
	(in thousands except per share amounts)			
2006 (1)				
Revenues	$711,997	$772,580	$741,319	$714,186
Income from continuing operations before taxes	349,353	(44,865)	544,966	246,763
Income from continuing operations	226,087	(30,705)	318,064	164,982
Net income	226,087	(30,705)	318,064	164,982
Basic earnings per share:				
Income from continuing operations	1.28	(0.17)	1.80	0.95
Net income	1.28	(0.17)	1.80	0.95
Diluted earnings per share:				
Income from continuing operations	1.26	(0.17)	1.75	0.94
Net income	1.26	(0.17)	1.75	0.94
2005 (2)				
Revenues	$368,212	$485,443	$632,088	$700,980
Income from continuing operations before taxes	174,482	224,405	241,136	328,637
Income from continuing operations	109,968	136,877	176,956	221,919
Net income	109,968	136,877	176,956	221,919
Basic earnings per share:				
Income from continuing operations	0.93	0.94	1.01	1.27
Net income	0.93	0.94	1.01	1.27
Diluted earnings per share:				
Income from continuing operations	0.92	0.91	0.99	1.18
Net income	0.92	0.91	0.99	1.18

(1) First quarter 2006 includes a mark-to-market gain of $39 million due to a loss of cash flow hedge accounting treatment for certain derivative instruments, and a loss of $25 million related to amounts previously recorded in AOCL due to a delay in the timing of production. Second quarter 2006 includes a loss of $399 million related to amounts previously recorded in AOCL due to the sale of Gulf of Mexico shelf properties. Third quarter 2006 includes a gain of $204 million from the sale of Gulf of Mexico shelf properties. Fourth quarter 2006 includes an additional gain of $7 million from the sale of Gulf of Mexico Shelf properties. See Note 3—Acquisitions and Divestitures and Note 12—Derivative Instruments and Hedging Activities.

(2) Fourth quarter 2005 includes discontinuation of hedge accounting treatment on certain derivatives resulting in a mark-to-market gain of $20 million ($13 million, net of tax) recognized in our consolidated results of operations. In addition, a loss of $52 million ($34 million, net of tax) associated with the discontinued hedge accounting treatment, which had been previously deferred in AOCL, was reclassified to earnings in fourth quarter 2005 as an increase in other expense, net in the consolidated statement of operations. See Note 4—Effect of Gulf Coast Hurricanes and Note 12—Derivative Instruments and Hedging Activities.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.
None.

Item 9A. Controls and Procedures.
Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures are effective.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management's Annual Report on Internal Control Over Financial Reporting
See Item 8. Management's Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting
Our management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

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

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2006. Based on our assessment, our internal controls over financial reporting were effective. Management included all consolidated entities of Noble Energy in its assessment. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information.
None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2006.

Item 11. Executive Compensation.
The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2006.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2006.

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2006.

Item 14. Principal Accounting Fees and Services.
The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2006.

PART IV

Item 15. Exhibits, Financial Statements Schedules.

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

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

SIGNATURES

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

NOBLE ENERGY, INC.
(Registrant)

Date: February 23, 2007	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, President, Chief Executive Officer and Director
Date: February 23, 2007	By: /s/ Chris Tong Chris Tong, Senior Vice President, Chief Financial Officer
Date: February 23, 2007	By: /s/ Frederick B. Bruning Frederick B. Bruning, Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 23, 2007
/s/ Chris Tong Chris Tong	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 23, 2007
/s/ Frederick B. Bruning Frederick B. Bruning	Chief Accounting Officer (Principal Accounting Officer)	February 23, 2007
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 23, 2007
/s/ Michael A. Cawley Michael A. Cawley	Director	February 23, 2007
/s/ Edward F. Cox Edward F. Cox	Director	February 23, 2007
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 23, 2007

/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 23, 2007
/s/ Bruce A. Smith Bruce A. Smith	Director	February 23, 2007
/s/ William T. Van Kleef William T. Van Kleef	Director	February 23, 2007

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
3.1	—	Certificate of Incorporation, as amended, of the Registrant as currently in effect (filed as Exhibit 3.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1987 and incorporated herein by reference).
3.2	—	Composite copy of Bylaws of the Registrant as currently in effect (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 29, 2002) dated February 8, 2002 and incorporated herein by reference).
4.1	—	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed as Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.2	—	Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.3	—	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7 1/4% Notes Due 2023, including form of the Registrant's 7 1/4% Notes Due 2023 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.4	—	Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.5	—	First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.6	—	Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7 1/4% Senior Debentures Due 2097 dated as of August 1, 1997 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
4.7	—	Rights Agreement, dated as of August 27, 1997, between the Registrant and Liberty Bank and Trust Company of Oklahoma City, N.A., as Right's Agent (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.8	—	Amendment No. 1 to Rights Agreement dated as of December 8, 1998, between the Registrant and Bank One Trust Company, as successor Rights Agent to Liberty Bank and Trust Company of Oklahoma City, N.A. (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form 8-A/A (Amendment No. 1) filed on December 14, 1998 and incorporated herein by reference).

Exhibit Number		Exhibit **
4.9	—	Third Indenture Supplement relating to $200 million of the Registrant's 5.25% Notes due 2014 dated April 19, 2004 between the Company and the Bank of New York Trust Company, N.A., as successor trustee to U.S. Trust Company of Texas, N.A. (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-116092) and incorporated herein by reference).
10.1 *	—	Restoration of Retirement Income Plan for Certain Participants in the Noble Energy, Inc. Retirement Plan dated September 21, 1994, effective as of May 19, 1994 (filed as Exhibit 10.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference).
10.2 *	—	Amendment No. 1 to the Restoration of Retirement Income Plan for Certain Participants in the Noble Affiliates Retirement Plan executed March 26, 2002 (filed as Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.3 *	—	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.4 *	—	Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates Thrift Restoration Plan dated May 9, 1994) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.5 *	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended, dated April 25, 2005, and approved by the stockholders of the Company on April 29, 2003 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference).
10.6 *	—	Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.7 *	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.8 *	—	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.9 *	—	Noble Energy, Inc. Non-Employee Director Fee Deferral Plan dated April 25, 2002 and effective as of April 23, 2002 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 and incorporated herein by reference).
10.10*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.29*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).
10.30*	—	Amendment No. 1 to the Noble Energy, Inc. Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).
10.31*	—	Consulting Agreement, dated May 9, 2005 but commencing May 16, 2005, by and between Noble Energy, Inc. and Thomas J. Edelman (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: May 16, 2005), filed May 20, 2005 and incorporated herein by reference).
10.32*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.33*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.34*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.35*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan entered into by certain executive officers and key employees of the Company on May 16, 2005 and August 1, 2005, respectively (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.36	—	Purchase and Sale Agreement dated May 15, 2006 by and between the Company and Coldren Resources LP (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 and incorporated herein by reference).
10.37*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 24, 2006) filed October 30, 2006 and incorporated herein by reference).
12.1	—	Computation of ratio of earnings to fixed charges.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Registered Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
23.3	—	Consent of Independent Registered Public Accounting Firm—UHY LLP, filed herewith.
23.4	—	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
31.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).

Exhibit Number		Exhibit **
31.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
99.1	—	Report of Independent Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
99.2	—	Report of Independent Public Accounting Firm—UHY LLP, filed herewith.
99.3	—	Report of Netherland, Sewell & Associates, Inc, filed herewith.

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

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

GLOSSARY

In this report, the following abbreviations are used:

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

DIRECTORS

CHARLES D. DAVIDSON (4)	Chairman of the Board, President and Chief Executive Officer, Noble Energy, Inc.
JEFFREY L. BERENSON (2) (3)	President and Chief Executive Officer, Berenson & Company
MICHAEL A. CAWLEY (1) (3)	Trustee, President and Chief Executive Officer, The Samuel Roberts Noble Foundation, Inc.
EDWARD F. COX *(2) (3) (4)*	*Partner, law firm of Patterson Belknap Webb & Tyler* LLP
THOMAS J. EDELMAN (4)	Former Chairman of the Board and Chief Executive Officer, Patina Oil & Gas Corporation
KIRBY L. HEDRICK (2) (3) (4)	Former Executive Vice President, Phillips Petroleum Company
BRUCE A. SMITH (1) (3)	Chairman, President and Chief Executive Officer, Tesoro Corporation
WILLIAM T. VAN KLEEF (1) (3)	Former Executive Vice President and Chief Operating Officer, Tesoro Corporation

COMMITTEE MEMBERSHIP (1) Audit Committee (2) Compensation, Benefits and Stock Options Committee (3) Corporate Governance and Nominating Committee (4) Environment, Health and Safety Committee

EXECUTIVE OFFICERS

CHARLES D. DAVIDSON	Chairman of the Board, President, Chief Executive Officer and Director
ALAN R. BULLINGTON	Senior Vice President, International
ROBERT K. BURLESON	Senior Vice President, Business Administration
SUSAN M. CUNNINGHAM	Senior Vice President, Exploration and Corporate Reserves
ARNOLD J. JOHNSON	Vice President, General Counsel and Secretary
DAVID L. STOVER	Executive Vice President and Chief Operating Officer
CHRIS TONG	Senior Vice President and Chief Financial Officer

CORPORATE INFORMATION

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Corporate Headquarters
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Houston, Texas 77067-3610
(281) 872.3100

INVESTOR RELATIONS
Greg Panagos
Director of Investor Relations
and Planning
(281) 872.3100
Investor_Relations@nobleenergyinc.com
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INDEPENDENT PUBLIC ACCOUNTANTS
KPMG LLP

TRANSFER AGENT AND REGISTRAR
Wells Fargo Bank, N. A.
Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075-1139
(800) 468.9716
stocktransfer@wellsfargo.com

COMMON STOCK LISTED
NEW YORK STOCK EXCHANGE
Symbol - NBL

ANNUAL MEETING
The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 24, 2007, at 9:30 a.m., Central Time, at the Company's headquarters located at 100 Glenborough Drive, Suite 100, Houston, TX 77067-3610. All stockholders are cordially invited to attend.

FORM 10-K
The Company's Annual Report on Form 10-K *for the year ended December 31, 2006,* as filed with the Securities and Exchange Commission, is included in this report. Additional copies are available without charge upon request by writing to the Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610, via the Company's Internet website: **http://www.nobleenergyinc.com**, or via the Securities and Exchange Commission's Internet website: **http://www.sec.gov**.

FORWARD LOOKING STATEMENT
This 2006 Annual Report to stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions *and are influenced by* various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 1A. Risk Factors. Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

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noble energy

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