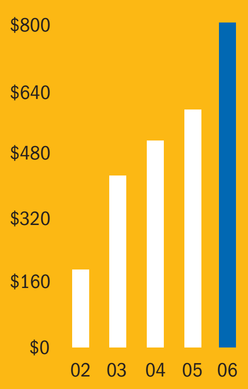
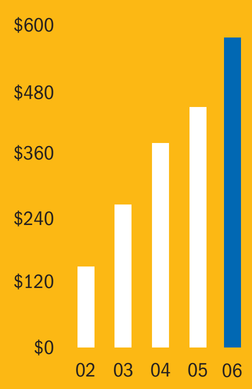
W&T OFFSHORE, INC. ANNUAL REPORT 2006

Summary Financial Data

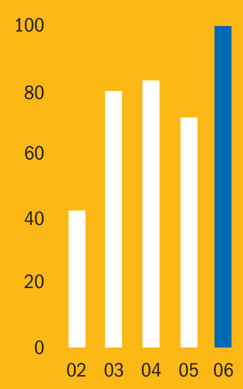
Financial Highlights (in thousands)	2006	2005	2004	2003	2002
Income Statement (year ended December 31)					
Total Revenues	$ 800,466	$ 585,136	$ 508,715	$ 422,587	$ 191,335
Operating Income	$ 317,615	$ 288,425	$ 231,332	$ 179,823	$ 57,458
Net Income	$ 199,104	$ 189,023	$ 149,482	$ 116,582	$ 2,049
Cash-Flow Statement (year ended December 31)					
Operating Activities	$ 571,589	$ 444,043	$ 377,275	$ 263,155	$ 147,809
Capex (incl. Acquisitions)	$ 1,658,541	$ 323,743	$ 284,847	$ 203,400	$ 116,759
Balance Sheet (as of December 31)					
Total Assets	$ 2,609,685	$ 1,064,250	$ 760,784	$ 546,729	$ 341,194
Long-Term Debt	$ 684,997	$ 40,000	$ 35,000	$ 67,000	$ 99,600
Shareholders' Equity	$ 1,042,917	$ 543,383	$ 359,878	$ 214,455	$ 133,330
Operating Data					
Natural Gas (MMcf)	60,447	46,548	53,348	52,807	39,368
Oil (MBbls)	6,456	4,085	4,847	4,373	2,465
Total Natural Gas and Oil (MMcfe)	99,181	71,060	82,432	79,045	54,158
Average Daily Equivalent Sales (MMcfe/d)	271.7	194.7	225.2	216.6	148.5
Average Realized Sales Price:					
Natural Gas ($/Mcf)	$ 7.08	$ 8.27	$ 6.18	$ 5.60	$ 3.34
Oil ($/Bbl)	$ 57.70	$ 48.85	$ 36.77	$ 28.74	$ 23.57
Estimated Net Proved Reserves					
Natural Gas (Bcf)	401.2	215.9	227.6	231.1	219.0
Oil (MMBbls)	55.7	45.9	40.0	35.6	23.1
Total (Bcfe)	735.2	491.5	467.5	444.7	357.5
Total Proved Developed (Bcfe)	478.9	318.6	290.2	295.6	229.2
Proved Undeveloped (Bcfe)	256.3	172.9	177.3	149.1	128.3
Proved Developed Reserves as a % of Proved Reserves	65.1%	64.8%	62.1%	66.5%	64.1%



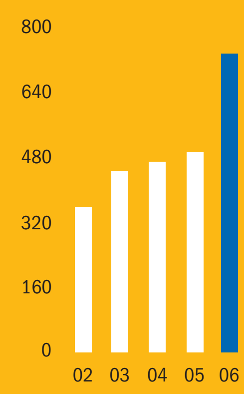
Revenues
(in Millions)



Cash Provided From Operating Activities
(in Millions)



Production
(Bcfe)



Proved Reserves
(Bcfe)

Forward-Looking Statements This Annual Report (including the letter from Tracy W. Krohn, our President and Chief Executive Officer) contains forward-looking statements within the meaning of the Private Litigation Securities Reform Act of 1995 that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in "Risk Factors" in Item 1A and "Factors That Could Affect Future Results" in Item 7A of the Form 10K included as part of and attached to this Annual Report and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend, to update these forward-looking statements.

TAKE W&T PUBLIC

W&T OFFSHORE'S STRATEGY IS SUCCEEDING. EVEN BEFORE OUR PUBLIC OFFERING IN 2005, WE HAD A LONG TRACK RECORD OF GROWING PROFITABLY THROUGH ACQUISITIONS AND OUR OWN EXPLORATION AND PRODUCTION ACTIVITIES.

Over the past decade, major oil companies and independents alike have faced a fundamental decision about the Gulf of Mexico: Is it better to focus more or less on the Gulf's maturing conventional shelf?

W&T DECISIONS ARE CLEARLY ALIGNED WITH SHAREHOLDERS' INTEREST. CEO AND CO-FOUNDER TRACY KROHN OWNS NEARLY 54 PERCENT OF THE COMPANY'S COMMON STOCK.

Major oil companies and a number of large independents chose to shift their focus and resources to other areas, including deepwater projects and international markets. W&T faced the same question, but we arrived at a different answer. We saw our competitors' divestitures in the Gulf as an opportunity to build a larger and more diverse Gulf of Mexico portfolio.

In short, we believed – and still do – that for a number of years to come, the Gulf of Mexico will offer E&P companies the potential for high cash flow and extremely attractive returns. To capitalize on that opportunity and acquire substantial properties, however, W&T needed additional cash.

Our initial public offering provided the access to capital required to dramatically expand our acquisition and drilling opportunities.

MAKE MAJOR GOM ACQUISITION

LESS THAN A YEAR AFTER OUR PUBLIC OFFERING, WE MET OUR GOAL OF MAKING A MAJOR PROPERTY ACQUISITION. THE TRANSACTION NEARLY DOUBLED W&T'S PRODUCTION AND INVENTORY OF PROSPECTS.

At the close of the $1 billion Kerr-McGee transaction, we added 90 drilling prospects to our inventory and boosted proven reserves by 245 Bcfe (billion cubic feet equivalent). We believe we can realize substantially greater reserves than we have currently booked.

In addition to providing strong production rates and a large inventory of prospects, the properties included a number of relatively easy-to-complete workover projects, which we identified during our due diligence.

The diversity of the properties is another plus. The new properties include a mix of oil and gas reserves, and also help spread the W&T portfolio over a wider area of the Gulf. This geographic diversification helps protect overall production when hurricanes strike the Gulf of Mexico.

Additionally, the large acreage component provides years of potential exploration opportunities.

W&T HAS APPROXIMATELY 2 MILLION ACRES UNDER CONTRACT – WHICH WE BELIEVE GIVES US THE THIRD-LARGEST ACREAGE POSITION ON THE CONVENTIONAL SHELF IN THE GULF OF MEXICO.

"Unlike at some other companies, a W&T employee not a contractor is the supervisor in charge at most of our platforms. He has stock in the company, real ownership and understands that what he does is important to increasing the value to shareholders and himself."

– Steve Schroeder, Senior Vice President and Chief Operating Officer

INTEGRATE/EXPLOIT NEW PROPERTIES

W&T ASSUMED OPERATIONS FOR THE NEW PROPERTIES IN LATE 2006. DURING 2007, WE WILL BRING PLATFORMS ON THESE PROPERTIES UP TO W&T STANDARDS, OPTIMIZE PRODUCTION AND PURCHASE NEW 3-D SEISMIC DATA TO HELP SUPPORT OUR EXPLORATION EFFORTS.

To facilitate a smooth transition, we hired 36 former operations personnel. Generally, their length of experience matches that of other W&T employees. We also added geoscientists and engineers during 2006.

Complete analysis of the drilling portfolio will take several years. That's typical of previous portfolio transactions. Today, for example, we are still drilling prospects from portfolio acquisitions four and five years ago.

W&T's production and exploitation expertise have helped to overcome the natural decline rates in our portfolio.

TRANSACTION HISTORY

Ability to overcome natural decline rates. Strong acquire and exploit capabilities.

Acquisition (year) Acquired	Initial Reserves	2003 YE Reserves	2004 YE Reserves	2005 YE Reserves	2006 YE Reserves
Vastar (1999)	18 Bcfe	64 Bcfe	59 Bcfe	49 Bcfe	46 Bcfe
Amoco (1999)	64 Bcfe	45 Bcfe	48 Bcfe	46 Bcfe	41 Bcfe
EEX (2000)	46 Bcfe	32 Bcfe	32 Bcfe	28 Bcfe	19 Bcfe
Burlington (2002)	120 Bcfe	137 Bcfe	140 Bcfe	168 Bcfe	137 Bcfe
ConocoPhillips (2003)	95 Bcfe	95 Bcfe	97 Bcfe	102 Bcfe	92 Bcfe
Results	**343 Bcfe**	**373 Bcfe**	**376 Bcfe**	**393 Bcfe**	**335 Bcfe**

"We've already completed some of the remediation work on our new properties. That's added 3 or 4 MMcfed (million cubic feet equivalent per day) to our production rate almost immediately."

– Harry Thrailkill, Senior Production Superintendent

EXPAND DEEP SHELF PROGRAM

THE DEEP SHELF, IN WHICH RESERVOIRS ARE LOCATED IN EXCESS OF 15,000 FEET, IS THE NEXT GREAT FRONTIER FOR W&T IN THE GULF OF MEXICO. OUR DEEP SHELF EXPERIENCE DATES BACK TO 2001.

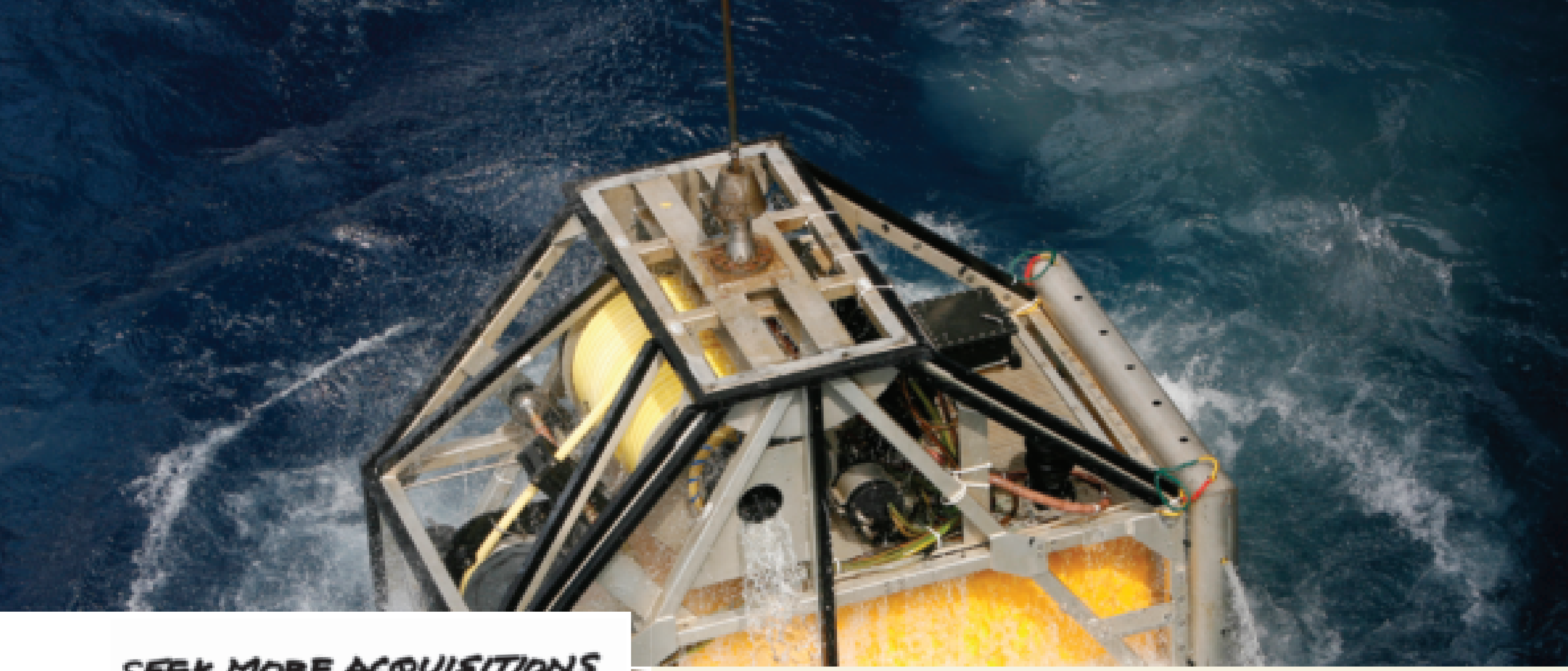
Our portfolio includes nearly 40 deep shelf drilling opportunities, with a total net unrisked reserve potential of about 5.5 Tcfe (trillion cubic feet equivalent). Our 2007 drilling plan includes several deep shelf wells, beginning with Ship Shoal 256 and South Timbalier 41.

While deep shelf drilling can be expensive, W&T can sometimes limit expenditures by drilling from an existing platform. New technology, such as advances in 3-D seismic or expandable tubular pipe that allows drillers to go deeper with larger casings, can lead to cost and operating benefits. Newer drilling rigs, which feature multiple pumps and higher-pressure capabilities, also can be an asset in drilling deeper.

WE SUCCESSFULLY DRILLED SEVEN OF EIGHT DEEP SHELF EXPLORATORY WELLS IN 2006.

"We have a large inventory of deep shelf wells that we can drill to potentially increase reserves from mature fields. That's a big opportunity to add value at locations where infrastructure already exists."

– Bill Voss, Vice President of Shelf Operations



SEEK MORE ACQUISITIONS

2007 LOOKS TO BE ANOTHER ACTIVE YEAR FOR ACQUISITION OPPORTUNITIES. IN ADDITION TO REACTING TO UNSOLICITED OPPORTUNITIES, WE ARE ACTIVELY SEEKING ACQUISITION AND DRILLING OPPORTUNITIES THROUGH NUMEROUS INDUSTRY AND POTENTIAL JOINT-VENTURE-PARTNER RELATIONSHIPS.

As a public company and an active acquirer, W&T has raised its profile and credibility among potential sellers and brokers. In 2006, that reputation earned us opportunities to review 12 portfolios valued at more than $200 million each.

Our size and reputation are advantages in seeking transactions. So is our conservative balance sheet. As a public company, we now have a variety of sources for financing, including cash generated by our own activities, traditional bank financing and public funding through debt or equity offerings.

As always, we seek underexploited properties, acreage and prospects that can keep our average reserve replacement costs among the industry's lowest. While prices being asked for properties are higher than in previous years, so are commodity prices. We remain prepared – financially and operationally – for the right opportunity.

"This is a dynamic company poised to expand. We have the competency and expertise to make it happen."

– Danny Gibbons, Chief Financial Officer

EXPLOIT GOM SHELF ACREAGE

IN 2007, W&T SEEKS TO EXTEND AN OUTSTANDING DRILLING RECORD ON THE CONVENTIONAL SHELF.

While deep shelf and deepwater reserves represent the long-term future of W&T Offshore, over 70 percent of proven reserves and over 80 percent of current production reside on the conventional shelf. In fact, 13 of our 20 largest fields by reserve size, are on the conventional shelf, which is defined as being less than 15,000 feet in well depth in water depths less than 500 feet.

For the five year period ending December 2006, the company has drilled 50 of 64 successful exploration conventional shelf wells, for a 78 percent success rate. In 2006, 9 of 12 exploration conventional shelf wells were successful. We have more than 100 drilling opportunities in the portfolio on the conventional shelf, with a combined net unrisked potential of 1.0 Tcfe.

Conventional shelf volumes should increase in 2007 over 2006 from a full year of production from new assets in the portfolio, the startup of several major projects and resumption of production shut in since the devastating 2005 hurricanes.

WE HAVE MORE THAN 100 DRILLING OPPORTUNITIES ON THE CONVENTIONAL SHELF.

“W&T is perceived as an up-and-coming company that’s highly motivated and good at what we do. That’s helped us attract experienced people who can help us continue to grow.”

– Cliff Williams, Vice President, Reservoir Engineering

CONTINUE TO REWARD SHAREHOLDERS

Dear Fellow Shareholders

THE STRATEGY THAT HAS SUSTAINED W&T OFFSHORE FOR MORE THAN 20 YEARS SUCCEEDED AGAIN IN 2006. REVENUES AND NET INCOME REACHED $800.5 MILLION AND $199.1 MILLION, RESPECTIVELY, THE HIGHEST LEVELS IN COMPANY HISTORY.

As the largest individual W&T shareholder, I'm acutely aware of the need to reward shareholders for their investments. You invest in W&T for the same reason I founded the company – to earn an attractive return.

The people of W&T Offshore worked hard on your behalf in 2006 to deliver that return. Their efforts produced increases in revenues over 2005 and increases in net income. Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) topped $641.5 million.

REVENUES, PRODUCTION AND RESERVES REACHED RECORD HIGHS IN 2006.

Expenses were higher in 2006, a result of total depletable costs due to the Kerr-McGee merger, increased capital spending, higher drilling and service costs, and higher estimated future development costs. As a result, earnings per diluted share declined slightly in 2006 to $2.84 from $2.87 in 2005.

Cash flow from operations increased to a record $572 million. This is especially significant as high cash flow contributes to our ability to fund drilling activities and future acquisitions.

Proved oil and gas reserves – the lifeblood of our ability to consistently produce such high returns – grew by 346 percent to 735 Bcfe (billion cubic feet equivalent). This was accomplished with the addition of reserves from the Kerr-McGee Oil & Gas Corporation transaction as well as through our own exploration efforts and reserve extensions.

Utilizing only estimates of proved reserves is an approach that undervalues the huge potential in our portfolio. Over the long run, I believe our reserves will actually become more valuable as we learn more about our fields and prospects.

Our excellent exploration track record continued. For the year, we achieved a combined 79 percent drilling success rate on exploratory and development wells, above the industry average. To put the odds even more in our favor, we continued our purchases of 3-D seismic data, with the goal of covering our entire two-million-acre Gulf of Mexico portfolio.

I'm also pleased to report that we had an excellent safety performance in 2006, which is vitally important to W&T employees and our partners. In recognition of safety and pollution prevention efforts, we were named a finalist for the Safety Awards for Excellence (SAFE) competition sponsored by the Minerals Management Service. We were just one of three companies recognized in the High Activity Outer Continental Shelf category.

2006 results confirmed the W&T strategy, proven over two decades. Executing our repeatable formula has produced excellent returns across a variety of market cycles. We believe that speaks well for our strategy and for our execution, which I believe is superior in the industry.

Here's how the W&T strategy worked in 2006.

✓ **GENERATE HIGH RETURN ON EQUITY** W&T earns extremely high returns on equity and capital. That cash is then redeployed quickly on new opportunities, including exploration drilling prospects or acquisitions.

✓ **ENHANCE RETURNS AND GROWTH RATE THROUGH THE DRILL BIT** Our ability to identify and exploit reserves was proved again in 2006. Organic growth – achieved through our own exploration and extension of reserves – added 109 Bcfe versus produced reserves of 99 Bcfe.

✓ **STRONG EMPHASIS ON CONVENTIONAL SHELF** In 2006, about 80 percent of our production and over 70 percent of our proved reserves were on the conventional shelf.

✓ **EXPAND TO OTHER PARTS OF THE GULF OF MEXICO** The depletion of oil and gas in the shallow-water Gulf of Mexico mandates a balanced approach that includes deep shelf and deepwater properties. In 2006, we continued our successful efforts in these regions. On the deep shelf alone, we have nearly 40 drilling opportunities with a net unrisked reserve potential of 5.5 Tcfe.

✓ **MAINTAIN FINANCIAL DISCIPLINE** By historically using debt only to fund acquisitions – not exploration drilling activities – we have maintained a conservative stance. During 2006, we offered shares of stock for sale, with the proceeds earmarked primarily to help finance a portion of the cash consideration related to the Kerr-McGee transaction and maintain a healthy balance sheet, effectively "reloading" the company.

✓ **CONTINUE TO ACQUIRE HIGH-QUALITY PROPERTIES**
Companies continue to divest high-quality Gulf of Mexico assets, and W&T continues to acquire them. In addition to closing the Kerr-McGee transaction in 2006, we reviewed more than a dozen opportunities to acquire additional properties, and see more opportunity in 2007.

In summary, 2006 proved our strategy and ability to manage through a variety of commodity pricing environments.

2007 AND BEYOND

WE HAVE A 5-YEAR BACKLOG OF EXPLORATION PROSPECTS.

As you can see from the previous pages in this report, we have a busy year ahead of us.

In 2007, we will be paying down some of the debt associated with the Kerr-McGee transaction. That's important because having less debt better equips us for other acquisition opportunities. Historically, W&T has paid its debt early, as evidenced in our cash-generating abilities.

In February 2007, we announced our $353 million capital budget plus $93 million of major maintenance and expense items. Depending on commodity prices and acquisition opportunities, we may boost our drilling budget later this year.

Even with a conservative drilling budget, we expect to be able to replace reserves. Overall, we believe production in 2007 will be in the range of 149 to 164 Bcfe. To accomplish this, we will focus on prospects with larger reserve potential.

Drilling costs – which accelerated in 2005 and 2006 – are beginning to moderate. As more new-build drilling rigs are completed and E&P drilling projects scale back, we expect drilling costs to fall. The current trend supports our approach of committing to short-term rig contracts only.

We entered 2007 fully equipped to make additional acquisitions. We strongly believe that we have sufficient access to capital markets necessary to support our ongoing growth strategy. Helping to guide our financially sound growth is a new member of our executive team. Senior Vice President and Chief Financial Officer John D. (Danny) Gibbons, who joined W&T in February 2007. Danny brings valuable experience from Westlake Chemical and Deloitte & Touche, and from Valero Energy, where he was Chief Financial Officer during a period of remarkable growth.

One other post-2006 development is our settlement of claims related to hurricanes Katrina and Rita and a well-control issue at Green Canyon 82. After adjustments for deductibles and money already collected, W&T received an additional $73.3 million in March 2007.

W&T Offshore is part of a vital industry. We benefit from the third-largest acreage position on the conventional shelf of the Gulf of Mexico. Most of that acreage is held by production, which perpetuates our lease rights without having to assure renewals. We've proven our ability to find energy reserves and acquire them at attractive prices.

WE FOCUS ON THE GULF OF MEXICO MARKET EXCLUSIVELY BECAUSE THE PROFIT MARGINS REMAIN VERY ATTRACTIVE.

Frequently, we are asked why we continue to focus exclusively on the Gulf of Mexico. The answer is simple: cash. We believe the lucrative profit margins in the Gulf of Mexico and potential rewards for shareholders are greater than with other basins around the world and domestically. When the numbers convince us to redirect our E&P focus, we will.

I think we offer an outstanding investment opportunity. Our full-economic cycle approach and proven ability to execute are an excellent foundation for producing higher returns year after year and reducing risk over the long term.

For our 250 employees, I want to thank you for your continued confidence and interest in W&T.

Very truly yours,

Tracy W. Krohn

Tracy W. Krohn
Founder and Chief
Executive Officer

Board of Directors

Tracy W. Krohn[3]
Chairman of the Board of Directors

Jerome F. Freel[3]
Founder, Secretary, Director
& Chairman Emeritus

Stuart B. Katz[1, 2]
Managing Director
Jefferies Capital Partners

Virginia Boulet[3]
Special Counsel
Adams & Reese LLP

James L. Luikart[1, 2]
Executive Vice President
Jefferies Capital Partners

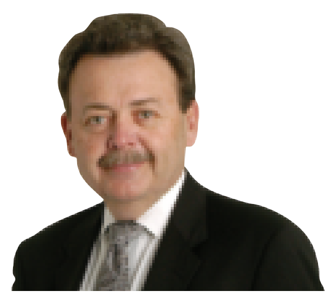
S. James Nelson, Jr.[1]
Chairman of the Company's Audit
Committee, Retired former Vice Chairman
of Cal Dive International
(Now Helix Energy Solutions)

1 Audit Committee Member 2 Compensation Committee Member 3 Nominating and Corporate Governance

Executive Officers

Tracy W. Krohn
Founder, Chairman, Chief Executive
Officer, President & Treasurer

Jerome F. Freel
Founder, Secretary, Director
& Chairman Emeritus



W. Reid Lea
Executive Vice President &
Manager of Corporate Development

Steve Schroeder
Senior Vice President
& Chief Operating Officer

Danny Gibbons
Senior Vice President
& Chief Financial Officer

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

Form 10-K

☒ **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 1-32414

W&T OFFSHORE, INC.
(Exact name of registrant as specified in its charter)

Texas	**72-1121985**
(State of incorporation)	**(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300 **Houston, Texas**	**77046-0905**
(Address of principal executive offices)	**(Zip Code)**

(713) 626-8525
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.00001	**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 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.

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

Indicate by check mark whether the registrant is a shell company. Yes ☐ No ☒

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $695,818,947 based on the closing sale price of $38.89 per share as reported by the New York Stock Exchange on June 30, 2006.

The number of shares of the registrant's common stock outstanding on March 1, 2007 was 75,894,334.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders to be held May 15, 2007 are incorporated by reference into Part III of this Form 10-K.

W&T OFFSHORE, INC.

TABLE OF CONTENTS

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Securities and Exchange Act that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A "Risk Factors" and Item 7A "Quantitative and Qualitative Disclosures About Market Risk" of this Annual Report on Form 10-K and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend, to update these forward-looking statements. Unless the context requires otherwise, references in this Annual Report on Form 10-K to "W&T," "we," "us" and "our" refer to W&T Offshore, Inc. and its consolidated subsidiaries.

PART I

Item 1. *Business*

We are an independent oil and natural gas acquisition, exploitation, exploration and production company. We are focused primarily in the Gulf of Mexico area, where we have developed significant technical expertise and where the high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid payback on our invested capital. We have leveraged our historic experience to focus on higher impact capital projects in the Gulf of Mexico, including the deepwater (water depths in excess of 500 feet), the deep shelf (well depths in excess of 15,000 feet), acquiring rights to develop and exploit new prospects and acquisitions of existing oil and natural gas properties.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultant, our total proved reserves at December 31, 2006 were 735.2 Bcfe. We calculate that our total proved reserves had a PV-10 of approximately $2.3 billion and a standardized measure of after-tax discounted cash flows of approximately $1.7 billion as of December 31, 2006. Of those reserves, 65% were proved developed, 35% were proved undeveloped, 55% were natural gas and 45% were oil.

We grow our reserves through acquisitions and drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that enable us to continue to add reserves post-acquisition. On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger for approximately $1.1 billion, subject to post-closing adjustments. We own the surviving entity, which is the successor to substantially all of Kerr-McGee's interests in Gulf of Mexico conventional shelf properties. The properties acquired include interests in approximately 100 fields on 242 offshore blocks (including 88 undeveloped blocks) spreading across the Western, Central and Eastern U.S. Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, additional debt and proceeds from the issuance of our common stock. During 2005 and 2004, we completed six acquisitions that were in support of our existing assets. Our acquisition team continues to work diligently to find properties that fit our profile and that we believe will add strategic and financial value to our company.

For the year ended December 31, 2006, capital expenditures of $1.7 billion included $1.1 billion for the Kerr-McGee transaction, $301.6 million for development activities, $252.0 million for exploration, $35.4 million for seismic and other leasehold costs and $4.8 million for other capital items. These amounts do not include $173.8 million of asset retirement obligations incurred during 2006—see Notes 2 and 20 to our consolidated financial statements. We participated in the drilling of 26 exploratory wells and eight development wells of which 19 were on the conventional shelf, nine were on the deep shelf and six were in the deepwater. All of the development wells were successful. Of the 26 exploration wells, 19 were successful and three of the successful wells are in the deepwater. We operate 12 of the 19 successful exploratory wells, including the three successful exploratory wells in the deepwater. Of the seven unsuccessful exploration wells, three were in the deepwater. During the three-year period ended December 31, 2006, we drilled 80 exploratory wells, of which 57 were successful (which we define as completed or planned for completion). For a more detailed discussion of our capital expenditures, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital expenditures.*"

During 2007, we expect to spend approximately $193 million on development activities, $133 million for exploration, $27 million for seismic (for a total of $353 million that will be capitalized), $31 million on expensed workovers and major maintenance projects, and $37 million for plugging and abandonment. We also anticipate that we could spend between $15 million to $20 million to repair damage to our facilities caused by Hurricanes Katrina and Rita. The timing of future repairs will be affected by equipment availability, design and remediation planning and permitting. For additional information regarding our expenditures to repair damage to our facilities caused by Hurricanes Katrina and Rita, see Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Insurance receivables."* We anticipate drilling 15 exploratory wells and three development wells in 2007.

We actively participated in bidding for Gulf of Mexico leases on the outer continental shelf ("OCS") at the March 2006 OCS Lease Sale 198 conducted by the U.S. government through the Minerals Management Service ("MMS"). Of the 7 bids we submitted, the MMS awarded us leases covering four OCS blocks located in the central Gulf of Mexico. Of the four blocks, three are in the deepwater and one is on the conventional shelf.

Business Strategy

We plan to continue to acquire and exploit reserves on the OCS, the area of our historical success, or in other areas outside of the Gulf of Mexico that are compatible with our technical expertise and could yield rates of return comparable to those we have historically achieved. We believe attractive acquisition opportunities will continue to arise in the Gulf of Mexico as the major integrated oil companies and other large independent oil and gas exploration and production companies continue to divest properties to focus on larger and more capital-intensive projects that better match their long-term strategic goals.

We believe our opportunities for deepwater exploration have been enhanced by technological advances in recent years that enable the connection of subsea wells to existing infrastructure over longer distances, eliminating the requirement for new, dedicated production facilities, the installation of which requires long lead times and large capital investments. We also believe asset divestitures and resource constraints of major integrated oil companies and other large upstream companies may allow us to acquire attractive deepwater prospects at favorable prices with a significant portion of the up-front development expenses, such as infrastructure and seismic, already invested.

We believe a significant portion of our acreage has exploration potential below currently producing zones, including deep shelf reserves. We consider deep shelf targets to be hydrocarbon-bearing horizons located in shallow water areas of the Gulf of Mexico at subsurface depths greater than 15,000 feet. Although the cost to drill deep shelf wells can be significantly higher than shallower wells, the reserve targets are typically larger, and the use of existing infrastructure, when available, can increase the economic potential of these wells.

We believe our financial approach has contributed to our success and has positioned us to capitalize on new opportunities. We typically limit our annual capital spending for exploration, exploitation and development activities to net cash provided by operating activities and use capacity under our credit facility for acquisitions and to balance working capital fluctuations.

Competition

The oil and natural gas industry is highly competitive. We are focused primarily in the Gulf of Mexico area and compete for the acquisition of oil and natural gas properties primarily on the basis of the price to be paid for such properties. We compete with numerous entities, including major oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours, which give them an advantage over us in evaluating and obtaining properties and prospects. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see Item 1A, "*Risk Factors.*"

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil and natural gas through third-party marketing companies. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2006 we sold over 10% of our production to Shell Trading and ConocoPhillips. Due to the nature of oil and natural gas markets and because oil and natural gas are commodities and there are numerous purchasers in the Gulf of Mexico, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services.

Similarly, the natural gas pipeline industry may also be subject to state regulations which may change from time to time. For instance, in response to a legislative directive, the Texas Railroad Commission recently completed a Natural Gas Pipeline Competition Study and is evaluating whether changes in regulations governing transportation and gathering services provided by intrastate pipelines and gatherers may be necessary. While the changes by these federal and state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected by any action taken materially differently than other natural gas producers with which we compete.

The Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers working in the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines.

Although the FERC has historically imposed light-handed regulation on offshore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the OCSLA over gathering facilities, if necessary, to permit non-discriminatory access to service. In an effort to heighten its oversight of the OCS, the FERC recently attempted to promulgate reporting requirements for all OCS "service providers," including gatherers, but the regulations were struck down as ultra vires by a federal district court, which decision was affirmed by the U.S. Court of Appeals in October 2003. The FERC withdrew its regulations in March 2004. Subsequently, in April 2004, the MMS initiated an inquiry into whether it should amend its regulations to assure that pipelines provide open and non-discriminatory access over OCS pipeline facilities. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation continue to be generally regulated by the FERC under the NGA and NGPA, as well as the OCSLA.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Oil and natural gas liquids transportation rates. Sales of crude oil, condensate and natural gas liquids by us are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally less rigorous than the FERC's regulation of natural gas pipelines under the Natural Gas Act. Regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, issued in October 1993, the FERC implemented regulations generally grandfathering all previously unchallenged interstate pipeline rates and made these rates subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge a market-based rate if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline. As provided for in Order No. 561, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing oil rate-indexing method. In December 2000, the FERC issued an order concluding that the rate index reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the D.C. Circuit, the FERC changed the rate indexing methodology to the Producer Price Index for Finished Goods, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. A challenge to FERC's remand order was denied by the D.C. Circuit in April 2004.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the method of drilling, casing, operating, plugging and abandoning wells, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

Federal leases. A substantial portion of our operations is located on federal oil and natural gas leases, which are administered by the MMS pursuant to the OCSLA. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed MMS regulations and orders that are subject to interpretation and change by the MMS.

For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities, structures and producer-operated pipelines located on the OCS to meet stringent engineering, construction and safety specifications. The MMS also has regulations restricting the flaring or venting of natural gas and prohibits the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial and there is no assurance that they can be obtained in all cases. We are currently exempt from supplemental bonding requirements by the MMS. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

The MMS also administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the MMS. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases previously relied on arm's-length sales prices and spot market prices as indicators of value. On May 5, 2004, the MMS issued a final rule that changed certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The final rule changed the valuation basis for transactions not at arm's-length from spot to the New York Mercantile Exchange prices adjusted for locality and quality differentials, and clarified the treatment of transactions under a joint operating agreement. We believe this rule will not have a material impact on our financial condition, liquidity or results of operations.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. The remediation, reclamation and abandonment of wells, platforms and other facilities is a significant expense of our operations. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

The effects of Hurricanes Ivan, Katrina and Rita during the 2004 and 2005 hurricane seasons significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-ups. The MMS continues to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce these effects, real and potential, in 2006 the MMS set forth guidance in an attempt to improve performance in the area of moored rig station-keeping during the environmental loading that may be experienced during hurricanes. Recommended practices for the use of moored rigs during the 2006 hurricane season were issued in a Notice to Lessees to ensure that consistent proper site assessments were performed and minimum design return periods were established across the Gulf of Mexico in an effort to decrease the amount of moored rig failures during hurricanes. It is anticipated that similar, if not more stringent, requirements will be issued by the MMS for the 2007 Hurricane Season. Rig availability may be impacted and therefore may pose a potential impact on our business; however, our competitors will be subject to the same market impacts.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years and the imposition of more stringent requirements could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and the Oil Pollution Act of 1990 ("OPA90") impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of oil or a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons are subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and certain other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste." Disposal of such non-hazardous oil and natural gas exploration, development and production wastes is usually regulated by state law. Other wastes handled at exploration and production sites or generated in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of "hazardous wastes," thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating cost, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Our operations are also subject to the Clean Air Act ("CAA") and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Cost may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended, establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus in order to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various permitted underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Federal Lease Stipulations address the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The MMS also issues numerous Notices to Lessees and Operators (NTLs) that provide formal guidelines on implementation of OCS regulations and standards. Recent NTLs prescribing measures to minimize threats to protected marine species with which we must comply include 2007-G03 *Marine Trash and Debris Awareness and Elimination*, 2007-GO4 *Vessel Strike Avoidance and Injured/Dead Protected Species Reporting*, and 2004-G06 *Structure Removal Operations*, among others. MMS conditions permit approvals on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area where we wish to conduct seismic surveys, development or abandonment operations, the work could be prohibited or delayed or expensive mitigation might be required.

Because our oil and natural gas operations include a production platform in the Gulf of Mexico located in a National Marine Sanctuary, we are also subject to additional federal regulation, including by the National

Oceanic and Atmospheric Administration ("NOAA"). Unique regulations related to operations in the sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Oil Pollution Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities.

Various pieces of equipment and structures we own have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, the costs of their disposal would increase. High lead levels in the paint might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and MMS to ensure worker safety during paint removal.

Naturally Occurring Radioactive Materials ("NORM") contaminate minerals, minerals extraction and processing equipment used in the oil and natural gas industry. The resulting NORM waste from such contamination is regulated by federal and state laws. Standards have been developed for worker protection; treatment, storage and disposal of NORM and NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use under RCRA and state laws. We do not anticipate any material expenditures in connection with our compliance with RCRA and applicable state law related to NORM waste.

We maintain insurance against sudden and accidental occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Seasonality

For a discussion of seasonal changes that affect our business, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Inflation and Seasonality.*"

Employees

As of December 31, 2006, we employed 251 people. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other items with the Securities and Exchange Commission ("SEC"). Our reports filed with the SEC are available free of charge to the general public through our website at *www.wtoffshore.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with the SEC. Requests for copies of this Annual Report and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. These reports are also available at the SEC Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The public may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and informational statements and other information regarding issuers that file electronically with the SEC.

Item 1A. *Risk Factors*

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and are subject to wide price fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we may periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. For example, in January 2006 we entered into commodity swap and option contracts relating to approximately 14 Bcfe, or 14%, of our production in 2006, 18 Bcfe of our anticipated production in 2007 and 11 Bcfe of our anticipated production in 2008. While these contracts are intended to reduce the effects of volatile oil and natural gas prices, they may also limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the contract. In addition, such 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 differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedge contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

Refer to Item 7A *"Quantitative and Qualitative Disclosures About Market Risk"* and Note 7 to our consolidated financial statements for additional information about our hedging arrangements.

Lower oil and gas prices could negatively impact our ability to borrow.

The availability under the revolving portion of our credit agreement is currently limited to $300 million, which may be increased under certain circumstances. Availability is determined periodically at the discretion of the banks and is based in part on oil and gas prices. Additionally, we may enter into agreements in the future that contain covenants limiting our ability to incur indebtedness in addition to that incurred under our existing credit agreement. These agreements may limit our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil and gas prices in the future could affect our ability to satisfy these covenants, ratios or other criteria and thus could reduce our ability to incur additional indebtedness.

As of December 31, 2006, approximately 35% of our total proved reserves were undeveloped and approximately 34% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

Less than four percent of our total proved reserves are non-producing due to damage caused by Hurricanes Katrina and Rita in 2005 and damage to the High Island Pipeline System which occurred in December 2006. While we have a development plan for exploiting and producing all of our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. We are not the operator with respect to 24% of our proved undeveloped and proved non-producing reserves, so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and non-producing reserves will ultimately be produced at the time periods we have planned, at the costs we have budgeted, or at all.

Relatively short production periods for our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace those reserves would result in decreasing reserves and production over time.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production. The vast majority of our current operations are in the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultant estimates that, on average, 50% of our total proved reserves are depleted within three years. As a result, our need to replace reserves from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a portion of their reserves outside the Gulf of Mexico in areas where the rate of reserve production is lower. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow production at rates we have recently experienced. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deep shelf and deepwater, actual oil and gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project.

Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Significant capital expenditures are required to replace our reserves.

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 and borrowings under our credit facility. In order to finance future capital expenditures, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our financial risk profile.

Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, debt or equity or other methods of financing on an economic basis to meet these requirements.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. By their nature, estimates of undeveloped reserves are less certain. Recovery of undeveloped reserves will require significant capital expenditures and successful drilling operations. Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than we have. We actively compete with other companies in our industry when acquiring new leases or oil and gas properties. For example, new leases acquired from the MMS are acquired through a "sealed bid" process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we compete with other companies in our industry for properties operated by third parties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence.

We conduct exploration, exploitation and production operations on the deep shelf and in the deepwater of the Gulf of Mexico, which presents unique operating risks.

The deep shelf and the deepwater of the Gulf of Mexico are areas that have had limited historical drilling activity due, in part, to their geological complexity, depth and higher cost. There are additional risks associated with deep shelf and deepwater drilling that could result in substantial cost overruns and/or result in uneconomic projects or wells. Deeper targets are more difficult to detect with traditional seismic processing. Moreover, drilling expense and the risk of mechanical failure are significantly higher because of the additional depth and adverse conditions such as high temperature and pressure. For example, deepwater wells require specific kinds of rigs with significantly higher day rates than those rigs used in shallow water and those rigs have limited availability. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than shelf development costs because deepwater drilling requires bigger installation equipment; sophisticated sea floor production handling equipment; expensive, state-of-the-art platforms and/or investment in infrastructure. Deep shelf development can also be more expensive than conventional shelf projects as deep shelf development requires more actual drilling days and higher drilling and services costs due to extreme pressure and temperatures associated with greater drilling depths. Accordingly, we cannot assure you that our oil and natural gas exploration activities, in the deep shelf, the deepwater and elsewhere, will be commercially successful.

We are not the operator on the properties representing 24% of our proved developed non-producing and proved undeveloped reserves, and therefore, we may not be in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves.

As we carry out our drilling program, we will not serve as operator of all planned wells. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital in drilling or acquisition activities. Approximately 23% of our proved undeveloped reserves and 25% of our proved developed non-producing reserves are on properties operated by others. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development activities may be unsuccessful for many reasons, including adverse weather conditions (such as hurricanes and tropical storms in the Gulf of Mexico), cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace reserves.

Our business involves a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as tropical storms, hurricanes and other adverse weather conditions;
- inability to obtain insurance at reasonable rates;
- failure to receive payment on insurance claims in a timely manner, or for the full amount claimed;
- pipe, cement, subsea well or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from tropical storms, hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties.

The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenue or curtailment of production from factors affecting the Gulf of Mexico specifically.

The geographic concentration of our properties along the Texas and Louisiana Gulf Coast and adjacent waters on and beyond the outer continental shelf means that some or all of our properties could be affected by the same event should the Gulf of Mexico experience:

- severe weather, including tropical storms and hurricanes;
- delays or decreases in production, the availability of equipment, facilities or services;
- delays or decreases in the availability of capacity to transport, gather or process production; or
- changes in the regulatory environment.

Because all our properties could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area. In 2006 we were forced to defer company-wide production of approximately 7.8 Bcfe as a result of Hurricanes Katrina and Rita, and in 2005 we were forced to defer company-wide production of approximately 17.4 Bcfe as a result of Hurricanes Cindy, Dennis, Katrina and Rita. During the three-year period ended December 31, 2006, we spent approximately $6.5 million to remediate hurricane damage that was not covered by insurance of which approximately $5.5 million related to Hurricanes Katrina and Rita in 2005.

Substantial acquisitions and exploitation activities could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of properties and our exploitation activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our financial risk profile. For instance, in 2006 we entered into a new credit agreement with an initial availability of $987.5 million and we received $307.0 of net proceeds from the sale of 9,775,000 shares of our common stock, principally in connection with the Kerr-McGee transaction. See Notes 4, 5 and 6 to our consolidated financial statements for additional details about these transactions.

Significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any contemplated future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Any failure to meet our debt obligations would adversely affect our business and financial condition.

As of December 31, 2006 we have approximately $685.0 million of long-term debt outstanding, of which $271.4 million is classified as current. As a result of our indebtedness, we will need to use a portion of our cash flow to pay principal and interest, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Interest rates for our new credit facility vary based upon utilization and whether the borrowings are at the base rate or the London Interbank Offering Rate (“LIBOR”). The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets or sell additional shares of common stock on terms that we do not find attractive, if it can be done at all.

Our credit agreement obligates us to comply with certain financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio beginning with the quarter ending on March 31, 2007, a minimum interest coverage ratio, a minimum asset coverage ratio and a maximum leverage ratio, as such ratios are defined in the agreement. Our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under the indebtedness, which could materially adversely affect our business, financial condition and results of operations.

Properties that we buy may not produce as projected and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program. Our acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

- acceptable prices for available properties;
- amounts of recoverable reserves;
- estimates of future oil and natural gas prices;
- estimates of future exploratory, development and operating costs;
- our estimates of the costs and timing of plugging and abandonment; and
- our estimates of potential environmental and other liabilities.

Our assessment of the acquired properties will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we have not historically inspected every well, platform or pipeline. Even if we had inspected each of these, our inspections may not have revealed structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

We may encounter difficulties integrating the operations of newly acquired oil and gas properties or businesses.

Increasing our reserve base through acquisitions is an important part of our business strategy. We may encounter difficulties integrating the operations of newly acquired oil and gas properties or businesses. In particular, we will face significant challenges in consolidating functions and integrating procedures, personnel and operations in an effective manner. The failure to successfully integrate such properties or businesses into our business may adversely affect our business and results of operations. Any acquisition we make may involve numerous risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets before our acquisition;
- our lack of drilling history in the geographic areas in which the acquired business operates;
- customer or key employee loss from the acquired business;
- increased administration of new personnel;
- additional costs due to increased scope and complexity of our operations; and
- potential disruption of our ongoing business.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. It is our current intention to continue focusing on acquiring properties with development and exploration potential located in the Gulf of Mexico area. To the extent that we acquire properties substantially different from the properties in our primary operating region or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as with acquisitions within our primary operating region. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

If oil and natural gas prices decrease, we may be required to write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Impairment of oil and natural gas properties*" for a discussion of the ceiling test.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of reserves shown in this report. Please read Item 1 "*Business"* and Item 2 *"Properties*" for information about our estimated oil and natural gas reserves.

In order to prepare the reserve estimates included in this report, our independent petroleum consultant projected production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be in our control. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, if natural gas prices decline by $0.10 per MMBtu, then the PV-10 value of our proved reserves as of December 31, 2006 would decrease from $2,336.4 million to $2,305.9 million. If oil prices decline by $1.00 per barrel, then the PV-10 value of our proved reserves as of December 31, 2006 would decrease from $2,336.4 million to $2,298.6 million.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest or have operating rights and have what our geoscientists believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion cost or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will be useful in predicting the characteristics and potential reserves associated with our drilling prospects. As we focus our drilling efforts on deepwater and deep shelf targets, our drilling activities will likely become more expensive. In addition, the geological complexity of deepwater and deep shelf formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, there can be no assurance that we will find commercially viable quantities of oil and natural gas and therefore, there can be no assurance that we will achieve our targeted rate of return or have a positive rate of return on investment.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, in some cases owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. In August 2005, all but three of our operated wells were temporarily shut in as a result of Hurricane Katrina and in September 2005 all of our operated wells were temporarily shut in as a result of Hurricane Rita.

In some cases, our wells are tied back to platforms owned by parties who do not have an economic interest in the well and we cannot be assured that such parties will continue to process our oil and natural gas.

In some cases, our wells are tied back to platforms owned by parties with no economic interests in our wells. Currently, a portion of our oil and natural gas is processed for sale on these platforms and no other processing facilities would be available to process such oil and natural gas without significant investment by us. Currently five fields, accounting for 107 Bcfe (or 14.5%) of our total proved reserves, are tied back or are planned to be tied back to separate, third-party host platforms. There can be no assurance that the owners of such platforms will continue to operate them. If any of these platforms ceases to operate its processing equipment, we may be required to shut in the associated wells.

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of oil and natural gas, and operating safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- land use restrictions;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation cost; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See Item 1 "*Business—Regulation*" for a more detailed description of our regulatory risks.

Our operations may incur substantial liabilities to comply with environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

We have, in the past, been subject to investigation with respect to allegations that we did not comply with applicable environmental laws and regulations. Resolution of these matters has required considerable management time and expense.

Changes in environmental laws and regulations occur frequently and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Our permits require that we report any incidents that cause or could cause environmental damages. See Item 1 *"Business—Regulation"* for a more detailed description of our environmental risks.

We operate a production platform in a National Marine Sanctuary.

Our oil and natural gas operation includes a production platform located in a National Marine Sanctuary in the Gulf of Mexico that is subject to special federal laws and regulations. Unique regulations related to operations in the Sanctuary include, among other things, prohibition of drilling activities within certain protected areas, restrictions on substances that may be discharged, depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief, including cessation of production from wells associated with this platform. As of December 31, 2006, fields associated with this platform had proved reserves of approximately 4.5 Bcfe, representing less than one percent of our total proved reserves.

The loss of senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Founder, Chairman, Chief Executive Officer and President; W. Reid Lea, our Executive Vice President and Manager of Corporate Development; John D. Gibbons, our Senior Vice President and Chief Financial Officer; Stephen L. Schroeder, our Senior Vice President and Chief Operating Officer; Jeffrey M. Durrant, our Senior Vice President of Exploration/Geoscience; or Joseph P. Slattery, our Senior Vice President of Operations, could have a negative impact on our operations. We do not maintain or plan to obtain any insurance against the loss of any of these individuals. Please read Item 4 "*Executive Officers of the Registrant*" for more information regarding the members of our management team.

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

The offshore oil and gas industry is experiencing significant shortages in the availability of certain drilling rigs as well as significant increases in the cost of utilizing drilling rigs. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition or results of operations. If the unavailability or high cost of rigs, equipment, supplies or personnel were particularly severe in Texas, Louisiana and the Gulf of Mexico, we could be materially and adversely affected because our operations and properties are concentrated in those areas. We must currently schedule rigs as much as four to nine months in advance for deepwater projects.

Counterparty credit risk may negatively impact the conversion of our accounts receivables to cash.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic or other conditions. In recent years, market conditions resulting in downgrades to credit ratings of energy merchants affected the liquidity of several of our purchasers. We continue to sell oil and natural gas to companies we believe are reasonable credit risks. In some cases, we have required purchasers to post letters of credit or provide other means of support to secure their performance under the purchase contracts. Based on the current demand for oil and natural gas, we do not expect that termination of sales to previous purchasers would have a material adverse effect on our ability to sell our production at favorable market prices.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

The occurrence of a significant accident or other event not fully covered or not covered by our insurance could have a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third party drilling contractors are used to drill our wells, we may not realize the full benefit of workmen's compensation laws in dealing with their employees. In addition, pollution and environmental risks generally are not fully insurable.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We will be exposed to larger uninsured losses in the future. The substantial insurance claims made by oil and gas producers in the Gulf of Mexico as a result of Hurricanes Katrina and Rita in 2005 have caused the cost of insurance to rise dramatically. The cost of our "control of well and offshore property insurance" was approximately $4 million for the twelve-month period ending July 31, 2006, with a deductible of $5 million. In July 2006, the Company renewed its insurance policy covering well control, property and hurricane damage for the combined W&T and Kerr-McGee properties at a cost of approximately $28.7 million. The policy limit is $100 million and carries a $10 million deductible. We are also exposed to the possibility that we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

We estimate that we could spend between $15 million to $20 million in 2007 to repair damage to our facilities caused by Hurricanes Katrina and Rita, the majority of which will not be covered by insurance. For additional information regarding our expenditures to repair damage to our facilities caused by Hurricanes Katrina and Rita, see Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Insurance receivables."*

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock in the public markets and the issuance of shares of common stock in future acquisitions.

Sales of a substantial number of shares of our common stock by us or by other parties in the public market or the perception that such sales may occur could cause the market price of our common stock to decline. In addition, the sale of such shares in the public market could impair our ability to raise capital through the sale of common or preferred stock.

In addition, in the future, we may issue shares of our common stock in connection with acquisitions of assets or businesses. If we use our shares for this purpose, the issuances could have a dilutive effect on the value of your shares, depending on market conditions at the time of an acquisition, the price we pay, the value of the business or assets acquired and our success in exploiting the properties or integrating the businesses we acquire and other factors.

Our stock price and trading volume may be volatile, which could result in substantial losses for our shareholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, industry or operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. Our current market price and valuation may not be sustainable. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly in the future. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Risks Related to Our Principal Shareholder, Tracy W. Krohn

We will be controlled by Tracy W. Krohn as long as he owns a majority of our outstanding common stock, and other shareholders will be unable to affect the outcome of shareholder voting during that time. This control may adversely affect the value of our common stock and inhibit potential changes of control.

Tracy W. Krohn controls approximately 40,863,307 shares of our common stock, representing approximately 53.8% of our voting interests as of March 1, 2007. As a result, Mr. Krohn has the ability to control the outcome of all matters requiring shareholder approval and other investors, by themselves, will not be able to affect the outcome of any shareholder vote. As a result, Mr. Krohn, subject to any fiduciary duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

- the composition of our board of directors and, through it, any determination with respect to our business direction and policies, including the appointment and removal of officers;
- the determination of incentive compensation, which may affect our ability to retain key employees;
- any determinations with respect to mergers or other business combinations;
- our acquisition or disposition of assets;
- our financing decisions and our capital raising activities;
- our payment of dividends on our common stock;
- amendments to our amended and restated articles of incorporation or bylaws; and
- determinations with respect to our tax returns.

Mr. Krohn is generally not prohibited from selling a controlling interest in us to a third party. In addition, his concentrated control could discourage others from initiating any potential merger, takeover or other change of control transaction that might be beneficial to our business. As a result, the market price of our common stock could be adversely affected.

In addition, because Mr. Krohn owns a majority of our common stock, we are a “controlled company” within the meaning of the rules of the New York Stock Exchange. As such, we are not required to comply with certain corporate governance rules of the New York Stock Exchange that would otherwise apply to us as a listed company on that exchange. These rules are generally intended to increase the likelihood that boards will make decisions in the best interests of shareholders. Specifically, we are not required to have a majority of independent directors on our board of directors, and we are not required to have nominating and corporate governance and compensation committees composed of independent directors. Should the interests of Mr. Krohn differ from those of other shareholders, the other shareholders will not be afforded the protections of having a majority of directors on the board who are independent from our principal shareholder.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

The majority of our fields are in the Gulf of Mexico. These fields are found in water depths ranging from less than ten feet up to 4,200 feet. The reservoirs in our fields are generally characterized as having high porosity and permeability, which typically result in high production rates. The following describes our ten largest fields as of December 31, 2006. At December 31, 2006, these fields accounted for approximately 47% of our PV-10 value, or $1.2 billion (before plugging and abandonment cost), and had proved reserves totaling 319 Bcfe.

Field Name	Field Category	Operator	Percent Natural Gas of Net Reserves	2006 Average Daily Equivalent Sales Rate (MMcfe/d) Gross	Net
Brazos A-133 (1)	Shelf	Apache	99%	61.9	12.9
East Cameron 321	Shelf	W&T	33%	10.3	8.6
High Island 177	Shelf	W&T	81%	13.6	11.3
Main Pass 108 (1)	Shelf	W&T	86%	23.9	13.3
Mississippi Canyon 718	Deepwater	Mariner	65%	15.2	5.0
Mobile 823	Shelf	ExxonMobil	90%	67.2	7.0
Ship Shoal 349	Shelf	W&T	13%	15.1	7.4
South Timbalier 41 (1)	Shelf/Deep shelf	Energy Partners	70%	104.4	34.3
South Timbalier 228	Shelf	W&T	17%	7.6	6.3
West Delta 30	Shelf	W&T and Anglo-Suisse (2)	1%	9.8	8.6

(1) Property was acquired in the Kerr-McGee merger transaction, and therefore the average daily equivalent sales rate is for the period August 24, 2006 to December 31, 2006.

(2) W&T operates all down hole operations.

Proved Reserves

Of our 735.2 Bcfe of proved reserves at December 31, 2006, 65% were proved developed, 35% were proved undeveloped, 55% were natural gas and 45% were oil. Our estimates of proved reserves were based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultant, and the reserve amounts are consistent with filings we make with federal agencies.

Our proved reserves as of December 31, 2006 are summarized below.

	As of December 31, 2006				
Classification of Reserves (1)	**Oil (MMBbls)**	**Gas (Bcf)**	**Total (Bcfe)**	**% of Total Proved**	**PV-10 (3) (In millions)**
Proved developed producing	11.5	156.4	225.3	31%	$ 741.3
Proved developed non-producing (2)	19.8	134.6	253.6	34%	974.9
Total proved developed	31.3	290.9	478.9	65%	1,716.2
Proved undeveloped	24.3	110.3	256.3	35%	620.2
Total proved	55.7	401.2	735.2	100%	$2,336.4

(1) Totals may not add due to rounding.

(2) Includes approximately 20.2 Bcfe of reserves with a PV-10 of $115.1 million that were shut-in at December 31, 2006 because of Hurricanes Katrina and Rita. We expect all of these reserves to be reclassified to producing in 2007. Also includes approximately 5.7 Bcfe of reserves with a PV-10 of $7.5 million that were shut-in at December 31, 2006 because of damage to the High Island Pipeline System which occurred in December 2006. The damage to the High Island Pipeline System was repaired in January 2007.

(3) The PV-10, as calculated by our independent petroleum consultant, has been adjusted by the Company to include estimated asset retirement obligations.

Acreage

The following summarizes gross and net developed and undeveloped acreage at December 31, 2006. Net acreage is our percentage ownership of gross acreage. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Shelf	1,267,225	594,750	469,405	360,665	1,736,630	955,415
Deepwater	132,270	65,620	133,265	107,345	265,535	172,965
	1,399,495	660,370	602,670	468,010	2,002,165	1,128,380

Approximately 70% of our total gross acreage is held-by-production, which permits us to maintain all of our exploration, exploitation and development rights (including deep rights below currently producing zones) to the leased area as long as production continues. We have the right to propose future exploration and development projects, including deep exploration projects, on the majority of our acreage.

Approximately 30% of our total gross acreage is not held by production and is undeveloped leasehold. Of our 602,670 total gross undeveloped acres, approximately 20% of our undeveloped leasehold could expire in 2007, 40% in 2008, 18% in 2009 and 22% in 2010 and beyond, if not extended by exploration and production activities prior to the applicable lease expiration dates.

Production

During 2006, our net production averaged approximately 272 MMcfe per day. Approximately 25.9 Bcfe of our proved developed reserves, representing less than four percent of our total proved reserves, remained shut-in at December 31, 2006 because of Hurricanes Katrina and Rita and damage to the High Island Pipeline System which occurred in December 2006. We expect all of these reserves to be reclassified to producing in 2007.

Production History

The following presents the historical information about our produced oil and natural gas volumes.

	Year Ended December 31,		
	2006	2005	2004
Net sales:			
Natural gas (Bcf)	60.4	46.5	53.3
Oil (MMBbls)	6.5	4.1	4.8
Total natural gas and oil (Bcfe)	99.2	71.1	82.4

Also refer to Item 6 *"Selected Consolidated Financial Data—Historical Reserve and Operating Information"* for additional historical operating data.

Productive Wells

The following presents our ownership at December 31, 2006 of our productive oil and natural gas wells, including wells that were temporarily shut-in on that date because of Hurricanes Katrina and Rita in 2005. A net well is our percentage working interest of a gross well.

	Oil Wells (1)		Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	126	101.9	124	90.3	250	192.2
Non-operated	131	36.6	153	35.4	284	72.0
	257	138.5	277	125.7	534	264.2

(1) Includes 11 gross (6.1 net) oil wells and 15 gross (7.2 net) gas wells with multiple completions.

Our ownership in wells that were temporarily shut-in at December 31, 2006 because of Hurricanes Katrina and Rita in 2005 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	13	8.7	7	5.8	20	14.5
Non-operated	11	1.8	25	2.5	36	4.3
	24	10.5	32	8.3	56	18.8

Drilling Activity

The following lists our successful exploratory wells that were drilled in 2006 and their estimated cost as of December 31, 2006 (dollars in millions):

Field	Working Interest	Estimated Cost Gross	Estimated Cost Net	Water Depth (feet)	Date Objective Drilled/Tested
Conventional Shelf:					
Eugene Island 205 C-2ST	100%	$ 5.0	$ 5.0	96	2nd Quarter
Galveston 303 #7	83%	9.7	9.0	64	4th Quarter
High Island 24L #1	25%	14.6	5.4	30	3rd Quarter
Mobile Bay 823 BB-2	100%	14.9	3.5	40	2nd Quarter
Ship Shoal 130 J-2	100%	6.1	6.1	47	1st Quarter
South Timbalier 206 A-10ST	25%	12.8	3.2	165	3rd Quarter
South Timbalier 230 A-7	100%	12.6	12.6	230	1st Quarter
West Delta 30 D-3ST	100%	4.0	4.0	45	2nd Quarter
West Delta 30 D-6ST	100%	2.4	2.4	45	2nd Quarter
Deep Shelf:					
Bay Junop S/L 17993 #1	100%	17.4	17.4	10	3rd Quarter
Eugene Island 205 C-3ST	100%	5.9	5.9	96	3rd Quarter
Eugene Island 205 C-4ST	100%	5.0	5.0	96	2nd Quarter
Grand Isle 3 #1	25%	12.0	3.9	25	1st Quarter
South Timbalier 41 #5 (F-1)	40%	18.1	7.2	71	3rd Quarter
Venice MLF C-11	100%	7.4	7.4	5	1st Quarter
West Cameron 295 #4ST	20%	9.8	2.2	48	3rd Quarter
Deepwater:					
Ewing Bank 977 #1ST	60%	9.8	5.9	550	1st Quarter
Green Canyon 82 #1	100%	20.9	20.9	2417	1st Quarter
Green Canyon 82 #3	100%	37.6	37.6	2417	3rd Quarter
		$226.0	$164.6		

Development Drilling

The following sets forth information relating to our development wells drilled over the past three fiscal years.

	Year Ended December 31, 2006	2005	2004
Gross Wells:			
Productive	8	6	7
Non-productive	—	1	—
	8	7	7
Net Wells:			
Productive	6.0	2.7	4.3
Non-productive	—	0.1	—
	6.0	2.8	4.3

Exploration Drilling

The following sets forth information relating to our exploration drilling over the past three fiscal years.

	Year Ended December 31,		
	2006	2005	2004
Gross Wells:			
Productive	19	17	21
Non-productive	7	5	11
	26	22	32
Net Wells:			
Productive	14.7	12.7	13.7
Non-productive	5.6	2.4	7.7
	20.3	15.1	21.4

Current Drilling Activity

We were in the process of drilling two gross (1.25 net) exploration wells and one gross (1.0 net) development well as of March 1, 2007.

Item 3. *Legal Proceedings*

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Currently, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations.

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

Not applicable.

Executive Officers of the Registrant

The following lists our executive officers:

Name	Age	Position
Tracy W. Krohn	52	Founder, Chairman, Chief Executive Officer, President and Director
J.F. Freel	94	Founder, Secretary, Director and Chairman Emeritus
W. Reid Lea	48	Executive Vice President and Manager of Corporate Development
John D. Gibbons	53	Senior Vice President and Chief Financial Officer
Stephen L. Schroeder	44	Senior Vice President and Chief Operating Officer
Jeffrey M. Durrant	52	Senior Vice President of Exploration/Geoscience
Joseph P. Slattery	54	Senior Vice President of Operations

Tracy W. Krohn has served as Chief Executive Officer and President since he founded the Company in 1983, as Chairman since 2004 and as Treasurer from 1997 until July 2006. Mr. Krohn's mother is married to J.F. Freel.

J.F. Freel has served as a director since our founding in 1983 and Secretary of the Company since 1984. Mr. Freel is married to Mr. Krohn's mother.

W. Reid Lea has served as the Company's Executive Vice President and Manager of Corporate Development since September 2005. He joined the Company as Vice President of Finance in 1999 and served as our Chief Financial Officer from 2000 until September 2005.

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. Prior to joining the Company, Mr. Gibbons was Senior Vice President and Chief Financial Officer of Westlake Chemical Corporation from March 2006 to February 2007. Prior to joining Westlake, Mr. Gibbons was with Valero Energy Corporation, beginning his career there in 1981, holding positions of increasing responsibility, ending as Executive Vice President and Chief Financial Officer. Prior to joining Valero, Mr. Gibbons spent five years working in the Houston office of Deloitte & Touche, where his practice was concentrated in the energy industry. Mr. Gibbons is a certified public accountant.

Stephen L. Schroeder joined the Company in 1998 and served as Production Manager from 1999 until 2005. In 2005, Mr. Schroeder was named Vice President of Production and in July 2006 he was named Senior Vice President and Chief Operating Officer.

Jeffrey M. Durrant serves as the Company's Senior Vice President of Exploration/Geoscience. He has been a member of our management team since 1997, initially as Geological Manager until 1999, then Exploration Manager until 2001 and Vice President of Exploration until 2005.

Joseph P. Slattery joined the Company in November 2002 and serves as our Senior Vice President of Operations. For more than eight years prior thereto, he was a major shareholder and president of Crescent Drilling & Production, Inc., a private consulting engineering firm specializing in total project management and field operations.

PART II

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

On January 28, 2005, certain shareholders of our common stock sold 12,655,263 shares pursuant to a registration statement that we filed with the Securities and Exchange Commission ("SEC") at an initial public offering price of $19.00 per share. Our common stock is listed and principally traded on the New York Stock Exchange under the symbol "WTI". The following sets forth, for each of the periods indicated, the high and low sales price of our common stock as reported on the New York Stock Exchange.

	High	Low
2005		
First Quarter (Beginning January 28, 2005)	$22.25	$18.05
Second Quarter	24.43	19.30
Third Quarter	34.44	24.03
Fourth Quarter	32.43	24.54
2006		
First Quarter	42.65	29.40
Second Quarter	49.16	31.50
Third Quarter	40.07	26.84
Fourth Quarter	37.45	26.99
2007		
First Quarter (Through March 1, 2007)	31.99	27.50

As of March 1, 2007, there were 157 registered holders of our common stock.

Dividends

Under the third amended and restated credit agreement that we entered into on May 26, 2006, we are allowed to pay annual dividends up to $30.0 million if we meet certain financial tests and are not in default. See Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources"* for more information regarding our credit agreement.

The following reflects the frequency and amounts of all cash dividends declared during the two most recent fiscal years (in thousands, except per share data):

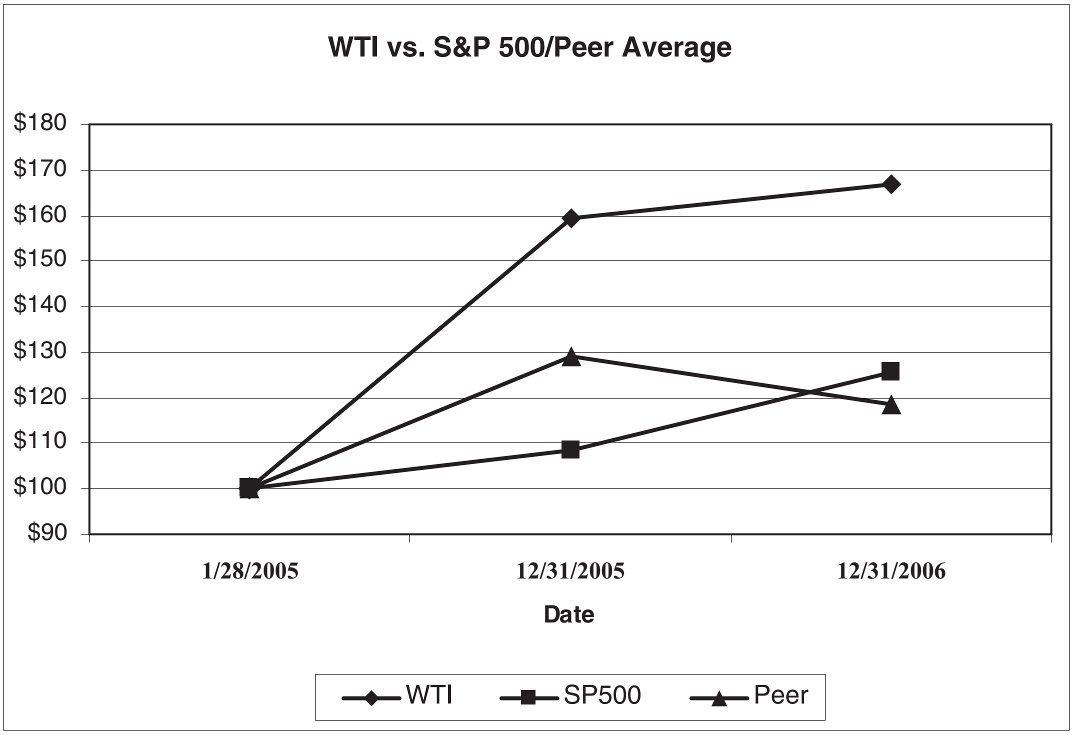
	Aggregate Dividends on Common Stock	Dividend per Share of Common Stock
2005		
First Quarter	$1,319	$0.02
Second Quarter	1,319	0.02
Third Quarter	1,320	0.02
Fourth Quarter	1,980	0.03
2006		
First Quarter	1,984	0.03
Second Quarter	1,984	0.03
Third Quarter	—	—
Fourth Quarter (1)	4,554	0.06

(1) A cash dividend of $0.03 per common share was declared on October 11, 2006 for the third quarter of 2006 and a cash dividend of $0.03 per common share was declared on December 11, 2006 for the fourth quarter of 2006.

On March 7, 2007, the Company's board of directors declared a cash dividend of $0.03 per share of common stock, payable on May 1, 2007 to shareholders of record on April 13, 2007. We currently expect that comparable cash dividends will continue to be paid in the future, subject to periodic reviews of the Company's performance by our board of directors.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 in our common stock on January 28, 2005 and the reinvestment of dividends thereafter.



Our peer group is comprised of ATP Oil & Gas Corp., Bois d'Arc Energy, Inc., Callon Petroleum Co., Energy Partners, Ltd., Mariner Energy, Inc. and Stone Energy Corp.

Item 6. ***Selected Consolidated Financial Data***

SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and with our consolidated financial statements and notes to those financial statements included elsewhere in this report. The consolidated statement of income information, consolidated cash flow information and the consolidated balance sheet information were derived from our audited financial statements. All share and per share information has been adjusted for the 6.669173211-for-one split of our common stock effective November 30, 2004.

	Year Ended December 31,				
	2006 (1)	2005	2004	2003 (1)	2002 (1)
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income Information:					
Revenues:					
Oil and natural gas	$ 800,348	$584,564	$508,195	$421,435	$189,892
Other	118	572	520	1,152	1,443
Total revenues	800,466	585,136	508,715	422,587	191,335
Operating costs and expenses:					
Lease operating	109,652	71,758	73,475	65,947	26,454
Gathering, transportation and production taxes	17,697	12,702	14,099	10,213	3,672
Depreciation, depletion and amortization	325,131	174,771	155,640	136,249	89,941
Asset retirement obligation accretion	12,496	9,062	9,168	7,443	—
General and administrative (2)(3)(4)	42,119	28,418	25,001	22,912	10,060
Commodity derivative gain (5)	(24,244)	—	—	—	—
Total operating costs and expenses	482,851	296,711	277,383	242,764	130,127
Impairment of subsidiary assets (6)	—	—	—	—	3,750
Income from operations	317,615	288,425	231,332	179,823	57,458
Interest expense, net of amounts capitalized	17,180	1,145	2,118	2,508	3,050
Other income (7)	5,919	2,746	276	279	49
Income before income taxes	306,354	290,026	229,490	177,594	54,457
Income taxes	107,250	101,003	80,008	61,156	52,408
Cumulative effect of change in accounting principle (net of taxes of $77)	—	—	—	144	—
Net income	199,104	189,023	149,482	116,582	2,049
Less preferred stock dividends	—	—	900	5,876	—
Net income applicable to common shares	$ 199,104	$189,023	$148,582	$110,706	$ 2,049
Earnings per common share (8):					
Basic earnings per share	$ 2.84	$ 2.91	$ 2.82	$ 2.14	$ —
Diluted earnings per share	2.84	2.87	2.27	1.79	—
Common stock dividends	8,522	5,938	3,550	35,124	—
Cash dividends per common share	0.12	0.09	0.07	0.67	—
Subchapter S corporation tax distributions (9)	—	—	—	—	13,883
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 571,589	$444,043	$377,275	$263,155	$147,809
Capital expenditures	1,658,541	323,743	284,847	203,400	116,759
Other Financial Information:					
EBITDA (10)	$ 655,242	$472,258	$396,140	$323,659	$147,399
Adjusted EBITDA	641,766	472,258	396,140	323,659	147,399

	December 31,				
	2006	2005	2004	2003	2002
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Total assets	$2,609,685	$1,064,520	$760,784	$546,729	$341,194
Long-term debt	684,997	40,000	35,000	67,000	99,600
Shareholders' equity	1,042,917	543,383	359,878	214,455	133,330

(1) In August 2006, we acquired working interests in approximately 100 oil and gas fields located in the Gulf of Mexico from Kerr-McGee Oil & Gas Corporation. In December 2003, we acquired working interests in 13 oil and gas fields located in the Gulf of Mexico from ConocoPhillips and in December 2002, we acquired working interests in 53 oil and gas fields located in the Gulf of Mexico from Burlington Resources, Inc.

(2) The amounts for 2006 and 2005 include expenses of $2.1 million and $2.4 million, respectively, associated with the temporary displacement of the employees who worked in our operations office in Metairie, Louisiana due to damage caused by Hurricane Katrina and the subsequent relocation of the majority of those employees to Houston, Texas. The amounts for 2005 and 2004 include expenses of $0.9 million and $1.5 million, respectively, associated with our initial public offering, which was completed in January 2005.

(3) In December 2004, our board of directors granted an employee bonus to all employees of record on December 31, 2004 (other than our Chief Executive Officer and our Corporate Secretary) in amounts equal to their 2004 salaries. The bonus was paid in two installments, on June 1, 2005 and January 3, 2006, to eligible individuals who were still in our employ on those dates. Approximately $2.6 million and $5.2 million of expenses related to this bonus are included in G&A for 2005 and 2004, respectively.

(4) G&A expenses related to our long-term incentive compensation plans were $8.4 million, $2.3 million, $0.6 million and $9.3 million in 2006, 2005, 2004 and 2003, respectively.

(5) For the year ended December 31, 2006, we recorded an unrealized gain of $13.5 million related to our open derivative contracts and we recorded a realized gain of $10.7 million related to settlements of our commodity derivatives. We did not engage in any hedging transactions during the other periods presented.

(6) This impairment is related to the sale of a subsidiary to two of our largest common shareholders for $1 million in cash.

(7) Primarily consists of interest income.

(8) Earnings per share information has not been presented for 2002 because we were an S corporation during the majority of that year. The results for that year would not be comparable to the presentation for the other years shown.

(9) On December 3, 2002, we revoked our election under Subchapter S of the Internal Revenue Code and began paying income tax at the corporate level.

(10) We define EBITDA as net income plus income tax expense, net interest (income) expense, and depreciation, depletion, amortization and accretion. Adjusted EBITDA excludes the unrealized gain or loss related to our open derivative contracts. Although not prescribed under generally accepted accounting principles, we believe the presentation of EBITDA and Adjusted EBITDA are relevant and useful because they help our investors understand our operating performance and make it easier to compare our results with those of other companies that have different financing, capital or tax structures. EBITDA and Adjusted EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. EBITDA and Adjusted EBITDA, as we calculate them, may not be comparable to EBITDA and Adjusted EBITDA measures reported by other companies. In addition, EBITDA and Adjusted EBITDA do not represent funds available for discretionary use. A reconciliation of our consolidated net income to EBITDA and Adjusted EBITDA is as follows:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Dollars in thousands)				
Net income	$199,104	$189,023	$149,482	$116,582	$ 2,049
Income taxes	107,250	101,003	80,008	61,156	52,408
Net interest expense (income)	11,261	(1,601)	1,842	2,229	3,001
Depreciation, depletion, amortization and accretion	337,627	183,833	164,808	143,692	89,941
EBITDA	655,242	472,258	396,140	323,659	147,399
Unrealized commodity derivative gain	(13,476)	—	—	—	—
Adjusted EBITDA	$641,766	$472,258	$396,140	$323,659	$147,399

HISTORICAL RESERVE AND OPERATING INFORMATION

The following presents summary information regarding our estimated net proved oil and natural gas reserves and our historical operating data for the years shown below. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC and give no effect to federal or state income taxes. For additional information regarding our reserves, please read Item 1 *"Business"* and Item 2 *"Properties."* The selected historical operating data set forth below should be read in conjunction with Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and with our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report.

	December 31,				
	2006	2005	2004	2003	2002
Reserve Data:					
Estimated net proved reserves (1):					
Natural gas (Bcf)	401.2	215.9	227.6	231.1	219.0
Oil (MMBbls)	55.7	45.9	40.0	35.6	23.1
Total natural gas and oil (Bcfe)	735.2	491.5	467.5	444.7	357.5
Proved developed producing (Bcfe)	225.3	120.1	145.8	135.5	108.1
Proved developed non-producing (Bcfe) (2)	253.6	198.5	144.4	160.1	121.1
Total proved developed (Bcfe)	478.9	318.6	290.1	295.6	229.2
Proved undeveloped (Bcfe)	256.3	172.9	177.3	149.1	128.3
Proved developed reserves as a percentage of proved reserves	65.1%	64.8%	62.1%	66.5%	64.1%
Reserve additions (Bcfe):					
Acquisitions	246.7	14.2	19.2	124.1	128.3
Extensions, discoveries and other additions	109.3	60.6	65.2	48.6	24.2
Revisions	(13.2)	20.3	20.9	(6.5)	15.0
Total net reserve additions	342.8	95.1	105.3	166.2	167.5

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Operating Data:					
Net sales:					
Natural gas (MMcf)	60,447	46,548	53,348	52,807	39,368
Oil (MBbls)	6,456	4,085	4,847	4,373	2,465
Total natural gas and oil (MMcfe) (1)	99,181	71,060	82,432	79,045	54,158
Average daily equivalent sales (MMcfe/d)	271.7	194.7	225.2	216.6	148.5
Average realized sales prices (3):					
Natural gas ($/Mcf)	$ 7.08	$ 8.27	$ 6.18	$ 5.60	$ 3.34
Oil ($/Bbl)	57.70	48.85	36.77	28.74	23.57
Natural gas equivalent ($/Mcfe)	8.07	8.23	6.16	5.33	3.50
Average per Mcfe data ($/Mcfe):					
Lease operating expenses	$ 1.11	$ 1.01	$ 0.89	$ 0.83	$ 0.49
Gathering and transportation costs and production taxes	0.18	0.18	0.17	0.13	0.07
Depreciation, depletion, amortization and accretion	3.40	2.59	2.00	1.82	1.66
General and administrative expenses	0.42	0.40	0.30	0.29	0.19
Total number of wells drilled (gross)	34	29	39	19	11
Total number of productive wells drilled (gross)	27	23	28	16	9

(1) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).
(2) Approximately 20.2 Bcfe of reserves were shut-in at December 31, 2006 because of Hurricanes Katrina and Rita. We expect all of these reserves to be reclassified to producing in 2007. Also includes 5.7 Bcfe of reserves that were shut in at December 31, 2006 because of damage to the High Island Pipeline System which occurred in December 2006. The damage to the High Island Pipeline System was repaired in January 2007.
(3) Average realized prices exclude the effects of our derivative contracts that do not qualify for hedge accounting. Had we included the effect of these derivatives, our average realized sales prices for natural gas and oil would have been $7.23 per Mcf and $57.97 per barrel, respectively, for 2006. On a natural gas equivalent basis, our average realized sales price would have been $8.18 per Mcfe for 2006. We did not have any derivative contracts in place during the other periods presented.

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

The following discussion and analysis should be read in conjunction with our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this annual report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this annual report.

Overview

We are engaged in oil and natural gas acquisition, exploitation, exploration and production activities, primarily in the Gulf of Mexico. We own working interests in approximately 158 producing fields in federal and state waters and we operate wells accounting for approximately 59% of our average daily production. We have interests in leases covering approximately two million acres spanning across the outer continental shelf off the coast of Louisiana, Texas, Mississippi and Alabama, which we believe makes us the third largest shelf acreage holder in the Gulf of Mexico. We own interests in approximately 523 offshore structures, of which 322 are platforms in the fields that we operate. We maintain these platforms and use them to separate oil and natural gas derived from nearby wells. In recent years, we have acquired interests in acreage and wells in the deepwater (more than 500 feet of water) off the outer continental shelf.

In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on profitably increasing production and reserves. We do not seek to increase production and reserves for the sake of growth. Rather, we acquire reserves or explore for new reserves where we believe we can achieve a rate of return on shareholders' equity over any five-year period comparable to our historic average. Our ability to control our costs over the past five years has contributed to the growth in our shareholders' equity. Certain risks are inherent in the oil and natural gas industry and our business, any one of which if it occurs, can negatively impact our ability to achieve historic rates of return on shareholders' equity.

We grow our reserves through acquisitions and drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that enable us to continue to add reserves post-acquisition. On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger for approximately $1.1 billion, subject to post-closing adjustments. We own the surviving entity, which is the successor to substantially all of Kerr-McGee's interests in Gulf of Mexico conventional shelf properties. The properties acquired include interests in approximately 100 fields on 242 offshore blocks (including 88 undeveloped blocks) spreading across the Western, Central and Eastern U.S. Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, additional debt and proceeds from the issuance of our common stock. During 2005 and 2004, we completed six acquisitions that were in support of our existing assets.

Our exploration efforts are balanced between discovering new reserves, discovering reserves associated with acquisitions, and discoveries on acreage already under lease. Historically, we have financed our exploratory drilling with net cash provided by operating activities. The investment associated with drilling a well and future development of a project principally depends upon the water depth of the well or project, the depth of the well or wells, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf. When projects are extremely capital intensive and involve substantial risk, we generally seek joint venture participants to share the risk.

We generally sell our oil and natural gas at the current market price at the wellhead, or we transport it to "pooling points" where it is sold. We are required to pay gathering and transportation cost with respect to a majority of our products. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product at the wellhead, the availability and cost of pipelines near the well or related production platforms, market prices, pipeline constraints and operational flexibility. During 2006, we sold an average of approximately 166 MMcf of natural gas per day and approximately 18,000 Bbls of oil per day. Our revenues in 2006 benefited from the Kerr-McGee transaction offset by lower average realized sales prices. In 2006, we recorded an unrealized gain of $13.5 million related to our open derivative contracts and we recorded a realized gain of $10.7 million related to settlements of our commodity derivatives. During the years ended December 31, 2005 and 2004 we did not engage in any commodity or financial hedging transactions.

Our operating costs involve the expense of operating our wells, platforms and other infrastructure in the Gulf of Mexico and transporting our products to the point of sale. Our operating costs are generally comprised of several components, including direct operating costs, repair and maintenance costs, transportation costs, production taxes, certain workover costs and ad valorem taxes. Our operating costs are driven in part by the type of commodity produced, the level of workover activity and the geographical location of the properties.

In recent years, we began to acquire and build platforms near the outer edge of the continental shelf and we began operating wells in the deepwater of the Gulf of Mexico. As we pursue our deepwater operations, our operating costs will likely increase. While each field can present operating problems that can add to the costs of operating a field, the production cost of a field is generally directly proportional to the number of platforms built in the field to handle production. As technologies have improved, it has become possible to produce oil and natural gas from a larger acreage area using a single platform, which may reduce the operating cost structure associated with recently developed fields.

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate any environmental damage our operations may have caused. The costs associated with our plugging and abandonment liabilities generally increase as we drill wells in the deeper parts of the continental shelf and the deepwater. We generally do not pre-fund our abandonment liabilities, which we estimated to be $314.1 million discounted at 8% at December 31, 2006, because we operate under an exemption from certain bonding requirements under MMS rules.

Production

During 2006, our net production averaged approximately 272 MMcfe per day. Approximately 25.9 Bcfe of our proved developed reserves, representing less than four percent of our total proved reserves, remained shut-in at December 31, 2006 because of Hurricanes Katrina and Rita and damage to the High Island Pipeline System which occurred in December 2006. We expect all of these reserves to be reclassified to producing in 2007.

Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Oil and natural gas revenues. Oil and natural gas revenues increased $215.7 million to $800.3 million for the year ended December 31, 2006. Natural gas revenues increased $42.8 million and oil revenues increased

$172.9 million. The natural gas revenue increase was primarily caused by a sales volume increase of 13.9 Bcf, which was partially offset by a 14% decrease in the average realized natural gas price from $8.27 per Mcf for the year ended December 31, 2005 to $7.08 per Mcf for the same period in 2006. The natural gas volume increase is primarily attributable to our acquisition of a wholly-owned subsidiary of Kerr-McGee by merger in August 2006 and the deferral of production in 2005 caused by Hurricanes Katrina and Rita. The oil revenue increase was caused by a sales volume increase of 2,371 MBbls and an 18% increase in the average realized price, from $48.85 per barrel in 2005 to $57.70 per barrel in 2006. The oil volume increase is primarily the result of successful drilling efforts, the Kerr-McGee transaction and the deferral of production in 2005 caused by Hurricanes Katrina and Rita.

Lease operating expenses. Our lease operating expenses increased from $71.8 million in 2005 to $109.7 million in 2006. The increase is primarily attributable to the Kerr-McGee transaction, higher insurance premiums as a result of the hurricanes in 2005, and an overall increase in service and supply costs at our existing properties. On a per Mcfe basis, lease operating expenses increased from $1.01 per Mcfe in the 2005 period to $1.11 per Mcfe for the same period in 2006 as a result of the aforementioned increase in insurance premiums and service and supply costs.

Gathering and transportation costs and production taxes. Gathering and transportation costs increased from $12.0 million in 2005 to $16.1 million in 2006, due primarily to higher throughput of natural gas and an increased ownership interest in 2006 at one of our processing facilities. Production taxes increased from $0.7 million in 2005 to $1.6 million in 2006 due to the Kerr-McGee transaction. Most of our production is from federal waters, where there are no production taxes.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion ("DD&A") increased from $183.8 million in 2005 to $337.6 million in 2006. The increase primarily reflects increases in total depletable costs due to the Kerr-McGee transaction, increased capital spending, higher drilling and service costs and higher estimated future development costs in 2006. The total amount of oil and gas properties and equipment, future development costs and future plugging and abandonment costs subject to DD&A, less related accumulated depreciation, was approximately $2.7 billion and $1.2 billion at December 31, 2006 and 2005, respectively. On a per Mcfe basis, DD&A was $3.40 for the year ended December 31, 2006, compared to $2.59 for the same period in 2005 due to the increase in our total depletable costs.

General and administrative expenses. General and administrative expenses ("G&A") increased from $28.4 million for the year ended December 31, 2005 to $42.1 million in the same period of 2006 primarily due to increased personnel and resources necessary to administer our growth and increased professional fees related to the requirement that the Company be able to provide management's assessment of internal control over financial reporting as prescribed by Section 404 of the Sarbanes-Oxley Act of 2002 as of December 31, 2006. G&A expenses related to our long-term incentive compensation plans were $8.4 million and $2.3 million in the years ended December 31, 2006 and 2005, respectively (see Note 12 to our consolidated financial statements). Also included in G&A for 2006 and 2005 are expenses of $2.1 million and $2.4 million, respectively, associated with the temporary displacement of the employees who worked in our operations office in Metairie, Louisiana due to damage caused by Hurricane Katrina and the subsequent relocation of the majority of those employees to Houston, Texas.

Commodity derivative gain. For the year ended December 31, 2006, we recorded an unrealized gain of $13.5 million related to our open commodity derivative contracts and a realized gain of $10.7 million related to settlements of our commodity derivative contracts.

Interest expense. Interest expense increased from $1.1 million for the year ended December 31, 2005 to $30.4 million in the same period of 2006 due primarily to higher average borrowings in 2006 related to the Kerr-McGee merger transaction. During 2006, $13.2 million of interest was capitalized to unevaluated oil and gas properties acquired in the Kerr-McGee transaction.

Other income. Other income, primarily consisting of interest income, increased from $2.7 million for the year ended December 31, 2005 to $5.9 million in the same period of 2006 due primarily to greater average daily balances of cash on hand in the 2006 period prior to the Kerr-McGee merger transaction and higher yields on cash investments.

Income tax expense. Income tax expense increased from $101.0 million in 2005 to $107.3 million in 2006 primarily due to increased taxable income. Our effective tax rate for the years ended December 31, 2006 and 2005 was approximately 35%.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and natural gas revenues. Oil and natural gas revenues increased $76.4 million to $584.6 million for the year ended December 31, 2005. Natural gas revenues increased $55.0 million and oil revenues increased $21.4 million. The natural gas revenue increase was caused by a 34% increase in the average realized natural gas price from $6.18 per Mcf for the year ended December 31, 2004 to $8.27 per Mcf for the same period in 2005, partially offset by a 6.8 Bcf sales volume decrease. The oil revenue increase was caused by a 33% increase in the average realized price, from $36.77 per barrel in 2004 to $48.85 per barrel in 2005, partially offset by a sales volume decrease of 762 MBbls. The volume decreases for oil and natural gas were primarily attributable to the deferral of production caused by Hurricanes Katrina and Rita.

Lease operating expenses. Our lease operating expenses decreased from $73.5 million in 2004 to $71.8 million in 2005 primarily due to a decrease in workover expenses. Included in 2005 is approximately $1.9 million to repair damage to our facilities caused by the two hurricanes. Lease operating expenses for 2005 also include approximately $1.1 million related to an employee bonus granted by our board of directors to all employees of record on December 31, 2004 (other than our Chief Executive Officer and our Corporate Secretary) in amounts equal to their 2004 salaries and approximately $0.4 million related to the W&T Offshore, Inc. 2005 Annual Incentive Plan (see Note 12 to our consolidated financial statements). On a per Mcfe basis, lease operating expenses increased from $0.89 per Mcfe in the 2004 period to $1.01 per Mcfe for the same period in 2005 primarily as a result of lower sales volumes in 2005.

Gathering and transportation costs and production taxes. Gathering and transportation costs decreased from $13.7 million in 2004 to $12.0 million in 2005, due primarily to a decrease in volumes transported, which was partially offset by increased cost of natural gas used in processing operations. Production taxes increased from $0.4 million in 2004 to $0.7 million in 2005 due to higher taxable values resulting from higher commodity prices in 2005. Most of our production is from federal waters, where there are no production taxes.

Depreciation, depletion, amortization and accretion. DD&A increased from $164.8 million in 2004 to $183.8 million in 2005. Although sales volumes were lower in 2005 compared to 2004, DD&A increased as a result of increased capital spending, higher drilling and service costs and higher anticipated future development costs in 2005. On a per Mcfe basis, DD&A was $2.59 for the year ended December 31, 2005, compared to $2.00 for the same period in 2004.

General and administrative expenses. G&A increased from $25.0 million for the year ended December 31, 2004 to $28.4 million in the same period of 2005. Included in G&A for 2005 are expenses of $2.4 million associated with the temporary displacement of the employees who worked in our operations office in Metairie, Louisiana due to damage caused by Hurricane Katrina and the subsequent relocation of the majority of those employees to Houston, Texas. During 2005 and 2004, we incurred $0.9 million and $1.5 million, respectively, of G&A related to our initial public offering, which was completed in January 2005. In December 2004, our board of directors granted an employee bonus to all employees of record on December 31, 2004 (other than our Chief Executive Officer and our Corporate Secretary) in amounts equal to their 2004 salaries. The bonus was paid in two installments, on June 1, 2005 and January 3, 2006 to eligible individuals who were still in our employ on those dates. Approximately $2.6 million and $5.2 million of expenses related to this bonus are included in G&A

for the years ended December 31, 2005 and 2004, respectively. G&A expenses related to our long-term incentive compensation plans were $2.3 million and $0.6 million in the years ended December 31, 2005 and 2004, respectively (see Note 12 to our consolidated financial statements). Also contributing to higher G&A expenses in 2005 were increases in personnel costs and legal and professional fees of $2.1 million and $0.4 million, respectively, resulting from increased personnel required to administer our growth and the additional costs of operating as a publicly traded company.

Interest expense. Interest expense decreased from $2.1 million for the year ended December 31, 2004 to $1.1 million in the same period of 2005 due primarily to lower average borrowings during 2005.

Other income. Other income, primarily consisting of interest income, increased from $0.3 million for the year ended December 31, 2004 to $2.7 million in the same period of 2005 due primarily to greater average daily balances of cash on hand in 2005 than in 2004.

Income tax expense. Income tax expense increased from $80.0 million in 2004 to $101.0 million in 2005 primarily due to increased taxable income. Our effective tax rate for the years ended December 31, 2005 and 2004 was approximately 35%.

Liquidity and Capital Resources

Cash flow and working capital. Net cash provided by operating activities for the year ended December 31, 2006 increased to $571.6 million, compared to $444.0 million for the comparable period in 2005 primarily due to higher volumes of oil and natural gas sold and realized gains on settlements of our commodity derivative contracts in 2006, partially offset by higher operating costs and interest expense in 2006, compared to 2005. Net cash used in investing activities totaled $1.7 billion and $321.5 million during 2006 and 2005, respectively, which primarily represents our investment in oil and gas properties. Included in the 2006 amount is approximately $1.1 billion, which represents the adjusted purchase price of the Kerr-McGee transaction which closed in August 2006. The final purchase price is subject to post-closing adjustments pursuant to and in accordance with the Merger Agreement. In 2006, net cash provided by financing activities was $935.9 million. In total, cash and cash equivalents decreased from $187.7 million as of December 31, 2005 to $39.2 million as of December 31, 2006.

Increases in our operating cash flows from 2004 through 2006 are attributable to several factors. In 2005, operating cash flows were favorably impacted by an increase in the average prices realized on sales of oil and natural gas, compared to 2004, and the deferral until the fourth quarter of 2006 of our estimated federal income tax payments originally due on September 15 and December 15, 2005 (see Note 8 to our consolidated financial statements). Offsetting these favorable factors were lower sales volumes in 2005 due to the deferral of production caused by Hurricanes Cindy, Dennis, Katrina and Rita. Production of approximately 5.7 Bcfe and 11.7 Bcfe was deferred during the third and fourth quarters of 2005, respectively, because of these storms. In 2006, operating cash flows were favorably impacted by higher volumes of oil and natural gas sold, primarily caused by the Kerr-McGee transaction and the deferral of production in 2005 caused by the hurricanes. Operating cash flows for 2006 were also favorably impacted by realized gains on settlements of our commodity derivative contracts. We did not have any derivative contracts in effect during 2005. Offsetting these favorable factors were higher operating costs and interest expense in 2006 primarily due to the Kerr-McGee transaction, and higher estimated federal income tax payments in 2006, as compared to 2005.

In anticipation of the financing of the Kerr-McGee transaction, in January 2006 we entered into commodity swap and option contracts relating to approximately 14 Bcfe, or 14%, of our production in 2006, 18 Bcfe of our anticipated production in 2007 and 11 Bcfe of our anticipated production in 2008. In August 2006, we entered into two interest rate swaps as required by our credit agreement, which serve to hedge the risk associated with the variable LIBOR rates used to reset the floating rates of our Tranche A and Tranche B term loans. For each of the interest rate swaps, we pay the counterparty the equivalent of a fixed interest payment on 50% of the aggregate outstanding principal balance of the Tranche A and Tranche B term loans and receive from the counterparty the equivalent of a floating interest payment based on a 3-month LIBOR rate calculated on the same notional amount. All interest rate swap payments are made quarterly and the LIBOR is determined in advance of each interest period. The fixed interest rates of the swaps related to the Tranche A and Tranche B term loans are 5.41% and 5.16%, respectively. The effective interest rates on the Tranche A and Tranche B loans were 13.5% and 8.6%, respectively, at December 31, 2006. While these contracts are intended to reduce the effects of volatile oil and gas prices and interest rates, they may also have the effect of limiting our potential income and exposing us to potential financial losses. We may enter into additional derivative contracts as management deems appropriate based upon prevailing prices.

The Katrina Emergency Tax Relief Act of 2005, signed on September 23, 2005, postponed tax deadlines with a due date falling on or after August 29, 2005 until February 28, 2006 for taxpayers affected by Hurricane Katrina. On February 17 and August 25, 2006, the Internal Revenue Service further postponed tax deadlines with a due date falling on or after August 29, 2005 until August 28 and October 16, 2006, respectively, for taxpayers affected by Hurricane Katrina. Consequently, our estimated federal income tax payments due in the third and fourth quarters of 2005 were paid on October 16, 2006 and totaled $33.5 million.

As of December 31, 2006, we had a working capital deficit of $315.4 million. Working capital deficits are not unusual at the end of a period and are usually the result of accounts payable related to exploration and development costs and/or current maturities of long-term debt. Current maturities of our long-term debt totaled $271.4 million as of December 31, 2006. We believe that cash provided by operations, borrowings available under our credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements. Under the terms of our credit agreement, we will be subject to a minimum current ratio as defined in the agreement beginning with the quarter ending on March 31, 2007. We were in compliance with all applicable covenants on December 31, 2006, and we expect to be in compliance with our covenants throughout 2007.

Insurance receivables. As of December 31, 2006 we have incurred $10.8 million of development costs and $85.9 million of production costs (consisting primarily of repairs and maintenance and well control expenses), net to our interest, to remediate damage caused by hurricanes Katrina and Rita which we reclassified to insurance receivables, excluding our deductibles. In 2006 we received reimbursements of our claims totaling $21.9 million. Included in insurance receivables at December 31, 2006 is $75.2 million, which represents the estimated reimbursable hurricane remediation costs incurred in excess of our deductibles, plus an insurance claim to recover reimbursable drilling costs on a well at Green Canyon 82 which experienced uncontrollable water flow in the second quarter of 2006.

In March 2007, the Company completed written settlement agreements with its insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as the claim related to Green Canyon 82. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company will receive additional proceeds of $73.3 million, currently expected in March 2007. Reimbursements totaling $78.1 million that will be received in 2007 exceeds our insurance receivables at December 31, 2006 by $2.9 million. Such amount will be used to offset hurricane remediation expenses incurred in 2007. We estimate that we could spend between $15 million to $20 million in 2007 to repair damage to our facilities caused by Hurricanes Katrina and Rita, the majority of which will not be covered by insurance. Uninsured expenditures will be recorded to development costs or production costs as incurred, based on the nature of the expenditure. The timing of future repairs will be affected by equipment availability, design and remediation planning and permitting.

In July 2006, the Company renewed its insurance policy covering well control, property and hurricane damage for the combined W&T and Kerr-McGee properties at a cost of approximately $28.7 million. The policy limit is $100 million and carries a $10 million deductible.

Capital expenditures. The level of our investment in oil and gas properties changes from time to time, depending on numerous factors, including the price of oil and gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2006, capital expenditures of $1.7 billion included approximately $1.1 billion for the Kerr-McGee transaction, $589.0 million for exploration, development, seismic and other leasehold costs and $4.8 million for other capital items. The amount for acquisition and other leasehold activity primarily represents the adjusted purchase price of the Kerr-McGee transaction which closed in August 2006. Our capital expenditures for the year ended December 31, 2006 were financed by net cash flow from operating activities, cash on hand and long-term borrowings, with the exception of the Kerr-McGee transaction, which was financed by cash on hand, long-term borrowings and proceeds from the issuance of our common stock.

During 2006, we participated in the drilling of 26 exploratory wells and eight development wells of which 19 were on the conventional shelf, nine were on the deep shelf and six were in the deepwater. All of the development wells were successful. Of the 26 exploration wells, 19 were successful and three of the successful wells are in the deepwater. We operate 12 of the 19 successful exploratory wells, including the three successful exploratory wells in the deepwater. Of the seven unsuccessful exploration wells, three were in the deepwater. Of the drilling, completion and facilities expenditures for 2006, we spent $222.2 million in the deepwater, $92.3 million on the deep shelf and $239.1 million on the conventional shelf and other projects. Additionally, we spent $12.5 million on expensed workovers and major maintenance projects and $24.5 million for plugging and abandonment expenses.

During 2005, we invested $323.0 million in oil and gas properties, including drilling 15.1 net exploration wells and 2.8 net development wells. During 2004, our oil and gas investments totaled $282.5 million, including drilling 21.4 net exploration wells and 4.3 net development wells. The wells we drilled over the past three years have tended to be deeper and involve more technological challenges than our past drilling projects and consequently, have been more expensive to drill.

During 2007, we expect to spend approximately $193 million on development activities, $133 million for exploration, $27 million for seismic (for a total of $353 million that will be capitalized), $31 million on expensed workovers and major maintenance projects, and $37 million for plugging and abandonment. We also anticipate that we could spend between $15 million to $20 million to repair damage to our facilities caused by Hurricanes Katrina and Rita. The timing of future repairs will be affected by equipment availability, design and remediation planning and permitting. We anticipate drilling 15 exploratory wells and three development wells in 2007. Our capital expenditures for 2007 are expected to be funded by cash flows from operating activities and borrowings under our credit agreement.

Periodically, we sell oil and gas properties that we identify as non-core, which we define as either having limited exploration or exploitation potential or which are not expected to yield our historic return on equity when abandonment costs are considered.

Long-term debt. On May 26, 2006, we entered into a new credit agreement principally in connection with the funding of the Kerr-McGee transaction. The new credit agreement became effective upon closing of the Kerr-McGee transaction in August 2006 and replaced our existing credit agreement dated March 15, 2005.

Our initial availability under the new credit agreement was $987.5 million. The credit agreement provides for (1) a revolving loan with an initial availability of $300.0 million, (2) a Tranche A term loan in the amount of $387.5 million and (3) a Tranche B term loan in the amount of $300.0 million. The amount available under the revolving loan is subject to redetermination on March 1 and September 1 of each year commencing September 1, 2007. Additionally, the agreement provides for the availability of letters of credit for up to $90.0 million, provided however, that its usage is subject to availability under the revolving loan.

Interest accrues either (1) at the higher of the Prime Rate, or the Federal Funds Rate plus 0.50%, plus a margin which varies from 0.0% to 1.75% depending upon the loan or (2) to the extent any loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate plus a margin that varies from 1.25% to

2.75% depending upon the loan. The Tranche A and Tranche B term loans are payable in installments and mature fifteen months from initial funding and on the fourth anniversary of initial funding, respectively. The revolving loan matures on the third anniversary of initial funding. The effective interest rates on the Tranche A, Tranche B and revolving loans were 13.5%, 8.6% and 10.5%, respectively, at December 31, 2006.

Substantially all of our oil and gas properties are pledged as collateral under our bank credit agreement. In addition, our credit agreement contains covenants that restrict the payment of cash dividends to a maximum of $30.0 million per year, borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. We are required to maintain interest rate hedging contracts with respect to at least 50% of the aggregate principal amount outstanding of the Tranche A and Tranche B term loans at all times, as well as maintain our commodity derivatives. We are also subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio beginning with the quarter ending on March 31, 2007, a minimum interest coverage ratio, a minimum asset coverage ratio and a maximum leverage ratio, as such ratios are defined in the agreement. We were in compliance with all applicable covenants on December 31, 2006.

We believe that we will have sufficient liquidity through access to the capital markets, operating cash flow and availability under our revolving loan to repay our current maturities of long-term debt and to fund our capital expenditure program.

At December 31, 2006, we had $122.0 million of borrowings outstanding on the revolving loan with $178.0 million of undrawn capacity. Also at December 31, 2006, borrowings outstanding on the Tranche A and Tranche B term loans totaled $563.0 million, net of unamortized discount of $12.0 million, of which $271.4 million is classified as current. Our scheduled debt payments are expected to be funded by cash on hand and cash flows from operating activities.

During the year ended December 31, 2006, we borrowed and repaid $1.1 billion and $485.5 million, respectively, under our credit agreement. During the years ended December 31, 2005 and 2004, we borrowed $42.6 million and $212.1 million, respectively, under our credit agreement to finance investments and acquisitions, but consistent with our conservative financial approach, we repaid these borrowings as soon as possible. Payments under our credit agreement totaled $37.6 million in 2005 and $244.1 million in 2004.

Equity offering. In July 2006, the Company completed an additional equity offering of 8,500,000 shares of its common stock at an offering price of $32.50 per share. The Underwriting Agreement also included a 30-day option that allowed the underwriters to purchase up to an additional 1,275,000 shares at the offering price, less underwriting discounts and commissions. In August 2006, the over-allotment option was exercised in full. Net proceeds generated by the offering and the exercise of the over-allotment option were approximately $307.0 million after underwriting discounts and commissions of approximately $9.5 million and legal, accounting, printing and various other fees of approximately $1.2 million. The net proceeds from the equity offering and the exercise of the over-allotment option were used in connection with the funding of the Kerr-McGee transaction.

Contractual obligations. The following summarizes our obligations and commitments as of December 31, 2006 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. At December 31, 2006, we did not have any capital leases or long-term contracts for drilling rigs or equipment.

	Payments Due by Period at December 31, 2006				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years
	(Dollars in millions)				
Contractual Obligations:					
Long-term debt	$ 697.0	$276.5	$128.0	$292.5	$ —
Seismic	37.9	23.7	14.2	—	—
Drilling rigs	23.9	23.9	—	—	—
Operating leases	7.5	2.0	3.1	2.4	—
Asset retirement obligations	314.1	41.7	52.1	33.5	186.8
Other liabilities	3.5	0.1	3.2	0.2	—
	$1,083.9	$367.9	$200.6	$328.6	$186.8

Inflation and Seasonality

Inflation. While we have benefited from a general rise in the price of both oil and natural gas over the last three years, increased prices for drilling rigs, drilling services, offshore transportation services and steel have impacted our lease operating expenses and our capital spending and we expect the prices of such goods and services may increase further in 2007. As we focus our exploratory efforts on deepwater and deep shelf targets, the drilling equipment that we need is more difficult to locate and more expensive.

Seasonality. Generally, the demand and price of natural gas increase during the winter months and decrease during the summer months. However, these seasonal fluctuations are somewhat reduced because, during the summer, pipeline companies, utilities, local distribution companies and industrial users purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. Crude oil and the demand for heating oil are also impacted by generally higher prices during winter months. Seasonal changes in the weather affect our operations. Tropical storms and hurricanes occur in the Gulf of Mexico during the summer and fall, which require us to evacuate personnel and shut-in production until these storms subside. Also, periodic storms during the winter often impede our ability to safely load, unload and transport personnel and equipment, which delays the installation of production facilities, thereby delaying sales of our oil and natural gas.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment or estimates by our management.

Revenue recognition. We recognize oil and gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectibility is reasonably assured. We use the sales method of accounting for oil and gas revenues from properties in which there is joint ownership. Under this method, we record oil and gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. As of December 31, 2006 and 2005, our natural gas imbalances were not significant.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A costs related to these activities is permitted. We capitalize external geological and geophysical costs, which mainly consist of seismic costs. Total capitalized geological and geophysical costs on our balance sheets were approximately $35 million and $28 million at December 31, 2006 and 2005, respectively. We expensed approximately $4.3 million in geological and geophysical administrative costs during each of the years 2006 and 2005, and approximately $2.5 million in 2004.

We amortize our investment in oil and natural gas properties through DD&A, using the units of production method. Unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are non-commercial. Total unproved properties excluded from amortization at December 31, 2006 were $308.2 million (a decrease from $391.7 million estimated at closing of the Kerr-McGee transaction). Prior to 2006, we did not exclude any expenditures related to our oil and gas properties from the amortization base.

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We capitalized $13.2 million of interest expense during the year ended December 31, 2006. We did not capitalize any interest during the years ended December 31, 2005 and 2004.

Under the full-cost method, sales of oil and natural gas properties are accounted for as adjustments to the full-cost pool with no gain or loss recognized, unless an adjustment would significantly alter the relationship between capitalized cost and the value of proved reserves.

Our financial position and results of operations could have been significantly different had we used the successful-efforts method of accounting for our oil and natural gas investments. GAAP allows successful-efforts accounting as an alternative method to full-cost accounting. The primary difference between the two methods is in the treatment of exploration cost, including geological and geophysical costs, and in the resulting computation of DD&A. Under the full-cost method, which we follow, exploratory costs are capitalized, while under successful-efforts, the cost associated with unsuccessful exploration activities and all geological and geophysical costs are expensed. In following the full-cost method, we calculate DD&A based on a single pool for all of our oil and natural gas properties, while the successful-efforts method utilizes cost centers represented by individual properties, fields or reserves. Typically, the application of the full-cost method of accounting for oil and natural gas properties results in higher capitalized cost and higher DD&A rates, compared to similar companies applying the successful efforts method of accounting.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural 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 periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, or FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- our estimates regarding the amount and timing of future operating cost, severance taxes, development cost and workover cost, all of which may in fact vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of oil and natural gas; and
- the judgments of the persons preparing the estimates.

Our proved reserve information as of December 31, 2006 included in this annual report is based on estimates prepared by our independent petroleum consultant, Netherland, Sewell & Associates, Inc. Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made. Unless otherwise indicated, we deduct plugging and abandonment expenses in our calculation of PV-10 reserve estimates. Approximately 69% of our total proved reserves at December 31, 2006 were classified as either proved undeveloped or proved developed non-producing reserves. Most of our proved developed non-producing reserves are "behind pipe" and will be produced after depletion of another horizon in the same well. Approximately 69% of these proved undeveloped reserves have been booked within one year of the most recent reserve report and approximately 74% of these proved undeveloped reserves have been booked within two years of December 31, 2006. Of the remaining 26%, consisting of reserves booked more than two years ago, all are wells that are either scheduled to be developed within the next three years or are waiting on a proved developed producing well to deplete in order to use the well bore to develop the target reserves.

Reporting of oil and gas production and reserves. We produce natural gas liquids as part of the processing of our natural gas. The extraction of natural gas liquids in the processing of natural gas reduces the volume of natural gas available for sale. In our December 31, 2006 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 3.0% of our total oil and gas revenues. Natural gas liquids are products sold by the gallon. Therefore, in reporting reserve and production amounts of natural gas liquids, we include this production in the oil category. Prices for natural gas liquids in 2006 were approximately 35% lower on average than prices for equivalent volumes of oil and average prices are expected to be 30% lower over the life of the reserves. We report our average oil prices realized after taking into account the effect of the lower prices received for sales of natural gas liquids. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of natural gas liquids.

We are periodically required to file estimates of our oil and gas reserves with various governmental authorities. In some cases, the basis for reporting estimates of proved reserves is different from the basis used for the estimated proved reserves in this report. Therefore, all proved reserve estimates may not be comparable. The major variations arise from differences in when the estimates are made, the definition of proved reserves, requirements to report in some instances on a gross, net or total operator basis and requirements to report in terms of smaller geographical units.

Impairment of oil and natural gas properties. Under the full-cost method of accounting, we are required periodically to compare the present value of estimated future net cash flows from our proved reserves (based on period-end commodity prices and excluding abandonment liabilities), net of tax, to the net capitalized cost of proved oil and natural gas properties, including estimated capitalized net abandonment cost, net of deferred taxes. This comparison is referred to as the full-cost "ceiling test." If the net capitalized cost of oil and natural gas properties in place exceeds the estimated discounted future net cash flows from proved reserves, we are required to write down the value of our oil and natural gas properties to the value of the discounted net cash flows and recognize an impairment charge. Any such write-downs are not recoverable or reversible in future periods. We did not have a ceiling test write-down during the years ended December 31, 2006, 2005 or 2004.

Asset retirement obligations. We have significant obligations to remove our equipment and restore land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Prior to 2003, under the full-cost method of accounting, the estimated undiscounted cost of our abandonment obligations, net of the value of salvage, were included as a component of our depletion base and expensed over the production life of the oil and natural gas properties. With the implementation of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* we are now required to record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

Inherent in the present value calculation are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of our existing abandonment liability, we will make corresponding adjustments to our oil and natural gas property balance. In addition, increases in the discounted abandonment liability resulting from the passage of time will be reflected as accretion expense in our consolidated statement of income.

In addition, the calculation of our standardized measure under SFAS No. 69 requires that we include estimated future cash flows related to the settlement of asset retirement obligations. Accordingly, we utilize the same estimate of our plugging and abandonment liability when calculating our standardized measure and PV-10 (discounted at 10%) as we do for purposes of calculating our asset retirement obligation under SFAS No. 143 (discounted at our credit-adjusted risk-free rate).

Income taxes. We provide for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. SFAS No. 109 requires the use of the liability method of computing deferred income taxes, whereby deferred income taxes are recognized for the future tax consequences of the differences between the tax basis of assets and liabilities and the carrying amount in our financial statements required by GAAP. 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. Because our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to reflect actual taxes paid in the period we complete our tax returns.

Share-based compensation. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), *Share-Based Payment.* In accordance with SFAS No. 123(R), compensation cost is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award.

New Accounting Policies and Pronouncements

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of SFAS No. 109*, ("FIN 48"), which clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It 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. Adoption of FIN 48 is not expected to have a material effect on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value as that term is used in many accounting pronouncements, establishes a framework for measuring the fair value of assets and liabilities as already required by generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently evaluating the impact that SFAS No. 157 may have on our consolidated financial statements.

For a more complete discussion of our accounting policies and procedures, see the notes to our consolidated financial statements.

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

We are exposed to market risks arising from fluctuating prices of crude oil, natural gas and interest rates as discussed below.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil and natural gas, which fluctuate widely. Oil and natural gas price declines and volatility could adversely affect our revenues, net cash flow provided by operating activities and profitability. For example, assuming a 10% decline in realized oil and natural gas prices and excluding the impact of our commodity derivatives, our 2006 income before income taxes would have declined by approximately 28%. If costs and expenses of operating our properties had increased by 10% in 2006, our income before income taxes would have declined by approximately 4%.

In connection with the anticipated financing of the transaction with Kerr-McGee, in January 2006 we entered into commodity swap and option contracts relating to approximately 14 Bcfe, or 14%, of our production in 2006, 18 Bcfe of our anticipated production in 2007 and 11 Bcfe of our anticipated production in 2008.

As of December 31, 2006, our open commodity derivatives were as follows:

Collars

Type	Commodity	Effective Date	Termination Date	Notional Quantity	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling	Fair Value (in thousands)
Funded	Natural Gas	1/1/2007	12/31/2007	8,016,000 MMBtu	$ 7.76	$16.80	$10,950
Zero Cost	Oil	1/1/2007	12/31/2007	1,569,500 Bbls	61.68	76.40	2,511
Funded	Natural Gas	1/1/2008	12/31/2008	5,124,000 MMBtu	7.31	15.80	3,413
Zero Cost	Oil	1/1/2008	12/31/2008	1,024,800 Bbls	60.00	74.50	73

While these contracts are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income if oil and natural gas prices were to rise substantially over the price established by the hedge. We do not enter into derivative contracts for trading purposes.

Interest rate risk. Interest rate risk is assessed by calculating the change in interest expense that would result from a hypothetical 100 basis point change in the interest rate on our weighted average borrowings under our credit facility for the year ended December 31, 2006. Interest rate changes will impact future results of operations and cash flows. Assuming the same average borrowings and excluding the impact of our interest rate swap contracts, a 100 basis point increase in interest rates would have increased our 2006 interest expense by approximately $2.6 million.

In connection with the Kerr-McGee merger transaction, our credit agreement required that we enter into interest rate swap contracts. In August 2006, we entered into two interest rate swaps, which serve to hedge the risk associated with the variable LIBOR rates used to reset the floating rates of our Tranche A and Tranche B term loans. For each of the interest rate swaps, we pay the counterparty the equivalent of a fixed interest payment on 50% of the aggregate outstanding principal balance of the Tranche A and Tranche B term loans and receive from the counterparty the equivalent of a floating interest payment based on a 3-month LIBOR rate calculated on the same notional amount. All interest rate swap payments are made quarterly and the LIBOR is determined in advance of each interest period. The fixed interest rates of the swaps related to the Tranche A and Tranche B term loans are 5.41% and 5.16%, respectively. As of December 31, 2006, the total notional amount of these swaps was $287.5 million. The effective interest rates on the Tranche A and Tranche B loans were 13.5% and 8.6%, respectively, at December 31, 2006. For additional details about our derivative contracts, refer to Note 7 to our consolidated financial statements.

Item 8. ***Financial Statements and Supplementary Data***

W&T OFFSHORE, INC. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2006 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
W&T Offshore, Inc. and Subsidiaries

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that W&T Offshore, Inc. and subsidiaries 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 (the COSO criteria). W&T Offshore, 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 W&T Offshore, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, W&T Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2006 consolidated financial statements of W&T Offshore, Inc. and subsidiaries and our report dated March 9, 2007, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 9, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
W&T Offshore, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of W&T Offshore, Inc. and subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of W&T Offshore, Inc. and subsidiaries' 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 and our report dated March 9, 2007, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 9, 2007

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 39,235	$ 187,698
Receivables:		
Oil and gas sales	98,362	43,892
Joint interest and other	50,681	33,097
Insurance receivables	75,151	6,634
Income taxes	15,705	—
Total receivables	239,899	83,623
Prepaid expenses and other assets	49,559	12,503
Total current assets	328,693	283,824
Property and equipment—at cost:		
Oil and gas properties and equipment (full cost method, of which $308,231 at December 31, 2006 and $0 at December 31, 2005 were excluded from amortization)	3,297,153	1,479,832
Furniture, fixtures and other	10,948	7,033
Total property and equipment	3,308,101	1,486,865
Less accumulated depreciation, depletion and amortization	1,042,315	717,583
Net property and equipment	2,265,786	769,282
Restricted deposits for asset retirement obligations	10,680	10,348
Other assets	4,526	1,066
Total assets	$2,609,685	$1,064,520
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt—net of discount	$ 271,380	$ —
Accounts payable	247,324	143,049
Undistributed oil and gas proceeds	46,933	11,667
Asset retirement obligations	41,718	39,653
Accrued liabilities	28,825	5,714
Current income taxes payable	—	31,609
Deferred income taxes—current portion	7,896	—
Total current liabilities	644,076	231,692
Long-term debt, less current maturities—net of discount	413,617	40,000
Asset retirement obligations, less current portion	272,350	112,621
Deferred income taxes	232,835	134,395
Other liabilities	3,890	2,429
Commitments and contingencies		
Shareholders' equity:		
Common stock, $0.00001 par value; 118,330,000 shares authorized; issued and outstanding 75,900,082 and 65,979,875 shares at December 31, 2006 and December 31, 2005, respectively	1	1
Additional paid-in capital	361,855	52,332
Retained earnings	681,634	491,050
Accumulated other comprehensive loss	(573)	—
Total shareholders' equity	1,042,917	543,383
Total liabilities and shareholders' equity	$2,609,685	$1,064,520

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2006	2005	2004
	(In thousands, except per share data)		
Revenues:			
Oil and natural gas revenues	$800,348	$584,564	$508,195
Other	118	572	520
Total revenues	800,466	585,136	508,715
Operating costs and expenses:			
Lease operating	109,652	71,758	73,475
Production taxes	1,556	712	375
Gathering and transportation	16,141	11,990	13,724
Depreciation, depletion and amortization	325,131	174,771	155,640
Asset retirement obligation accretion	12,496	9,062	9,168
General and administrative	42,119	28,418	25,001
Commodity derivative gain	(24,244)	—	—
Total costs and expenses	482,851	296,711	277,383
Operating income	317,615	288,425	231,332
Interest expense:			
Incurred	30,418	1,145	2,118
Capitalized	(13,238)	—	—
Other income	5,919	2,746	276
Income before income taxes	306,354	290,026	229,490
Income taxes	107,250	101,003	80,008
Net income	199,104	189,023	149,482
Less preferred stock dividends	—	—	900
Net income applicable to common shares	$199,104	$189,023	$148,582
Earnings per common share:			
Basic	$ 2.84	$ 2.91	$ 2.82
Diluted	2.84	2.87	2.27

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Preferred		Common		Additional		Accumulated Other	Total
	Shares	Value	Shares	Value	Paid-In Capital	Retained Earnings	Comprehensive Loss	Shareholders' Equity
	(In thousands, except per share data)							
Balances at January 1, 2004	2,000	$ 45,435	52,517	$—	$ 6,087	$162,933	$ —	$ 214,455
Cash dividends:								
Common stock ($0.07 per share)	—	—	—	—	—	(3,550)	—	(3,550)
Preferred stock ($0.45 per share)	—	—	—	—	—	(900)	—	(900)
Common stock issued	—	—	95	—	391	—	—	391
Net income	—	—	—	—	—	149,482	—	149,482
Balances at December 31, 2004	2,000	45,435	52,612	—	6,478	307,965	—	359,878
Cash dividends:								
Common stock ($0.09 per share)	—	—	—	—	—	(5,938)	—	(5,938)
Conversion of preferred stock to common stock	(2,000)	(45,435)	13,338	1	45,435	—	—	1
Common stock issued	—	—	30	—	419	—	—	419
Net income	—	—	—	—	—	189,023	—	189,023
Balances at December 31, 2005	—	—	65,980	1	52,332	491,050	—	543,383
Cash dividends:								
Common stock ($0.12 per share)	—	—	—	—	—	(8,520)	—	(8,520)
Common stock issued	—	—	145	—	2,544	—	—	2,544
Common stock issued—equity offering	—	—	9,775	—	306,979	—	—	306,979
Net income	—	—	—	—	—	199,104	—	199,104
Other comprehensive loss, net of tax	—	—	—	—	—	—	(573)	(573)
Balances at December 31, 2006	—	$ —	75,900	$ 1	$361,855	$681,634	$(573)	$1,042,917

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Operating activities:			
Net income	$ 199,104	$ 189,023	$ 149,482
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	337,627	183,833	164,808
Amortization of debt issuance costs	1,417	342	461
Accretion of discount on long-term debt	6,765	—	—
Share-based compensation	2,544	419	391
Unrealized commodity derivative gain	(13,476)	—	—
Deferred income taxes	106,645	42,302	40,189
Other	511	11	—
Changes in operating assets and liabilities:			
Oil and gas receivables	(54,470)	(3,465)	(1,320)
Joint interest and other receivables	(17,584)	(10,933)	2,019
Insurance receivables	(61,301)	(6,633)	—
Income taxes	(47,313)	40,731	(25,410)
Prepaid expenses and other assets	(27,168)	(3,211)	(2,397)
Asset retirement obligations	(24,492)	(17,868)	(12,857)
Accounts payable and accrued liabilities	162,274	29,492	59,481
Other liabilities	506	—	2,428
Net cash provided by operating activities	571,589	444,043	377,275
Investing activities:			
Acquisition of Kerr-McGee properties	(1,061,769)	—	—
Investment in oil and gas property and equipment	(588,978)	(322,984)	(282,510)
Proceeds from sales of oil and gas properties and equipment	—	2,547	3,127
Purchases of furniture, fixtures and other, net	(4,825)	(759)	(2,337)
Other	(331)	(277)	1,854
Net cash used in investing activities	(1,655,903)	(321,473)	(279,866)
Financing activities:			
Borrowings of long-term debt	1,123,732	42,550	212,100
Repayments of borrowings of long-term debt	(485,500)	(37,550)	(244,100)
Proceeds from equity offering, net of costs	306,979	—	—
Dividends to shareholders	(8,225)	(3,958)	(4,450)
Debt issuance costs	(1,135)	(889)	—
Net cash provided by (used in) financing activities	935,851	153	(36,450)
(Decrease) increase in cash and cash equivalents	(148,463)	122,723	60,959
Cash and cash equivalents, beginning of period	187,698	64,975	4,016
Cash and cash equivalents, end of period	$ 39,235	$ 187,698	$ 64,975

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and subsidiaries (the "Company") is an independent oil and natural gas acquisition, exploitation, exploration and production company focused primarily in the Gulf of Mexico.

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc. and its majority owned subsidiaries. All significant intercompany transactions and amounts have been eliminated for all years presented.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from those estimates.

Cash Equivalents

We consider all highly liquid investments purchased with original or remaining maturities of three months or less at the date of purchase to be cash equivalents.

Revenue Recognition

We recognize oil and gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectibility is reasonably assured. We use the sales method of accounting for oil and gas revenues from properties in which there is joint ownership. Under this method, we record oil and gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. As of December 31, 2006 and 2005, our natural gas imbalances were not significant.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies. Our production is sold utilizing month-to-month contracts that are based on prevailing prices. We historically have not had any significant problems collecting our receivables, except in rare circumstances; therefore, we do not maintain an allowance for doubtful accounts.

The following identifies customers from whom we derived 10% or more of our total oil and gas revenues.

	Year Ended December 31,		
	2006	2005	2004
Customer			
Shell Trading (US) Company	28%	21%	21%
BP	10%	19%	22%
Cinergy Corp.	**	18%	**
ConocoPhillips	14%	17%	20%

** less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and gas production.

Oil and Gas Properties and Equipment

We use the full-cost method of accounting for oil and gas properties. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include costs of drilling exploratory wells and external geological and geophysical costs which mainly consist of seismic costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, certain geological and geophysical costs and general and administrative costs are expensed in the period incurred.

Oil and gas properties and equipment include costs of unproved properties. Unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are non-commercial.

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We did not capitalize any interest during the years ended December 31, 2005 and 2004.

Oil and gas properties included in the amortization base are amortized using the unit-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs to be incurred in developing proved reserves as well as estimated plugging and abandonment costs, net of salvage value, that have not yet been capitalized as asset retirement costs.

Sales of proved and unproved oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

Under the full cost method of accounting, we are required to periodically perform a "ceiling test" which determines a limit on the book value of our oil and gas properties. If the net capitalized cost of proved oil and gas properties, net of related deferred income taxes, plus the cost of unproved oil and gas properties, exceeds the present value of estimated future net cash flows from proved reserves discounted at 10%, net of related tax effects, plus the cost of unproved oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. Future net cash flows are based on period-end commodity prices and exclude future cash outflows related to estimated abandonment costs. We did not have a ceiling test impairment during the years ended December 31, 2006, 2005 or 2004.

Furniture, fixtures and non-oil and gas property and equipment are depreciated using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from five to seven years. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred.

Derivative Financial Instruments

Our market risk exposures relate primarily to commodity prices and interest rates. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. Our derivative instruments currently consist of commodity swap and option contracts and interest rate swap contracts entered into with financial institutions. We do not enter into derivative instruments for speculative trading purposes.

We account for our derivative contracts in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 133, as amended, requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Additionally, the statement requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is entered into.

Changes in the fair value of our commodity derivative contracts are recognized currently in earnings. Our interest rate swaps qualify as cash flow hedges under SFAS No. 133, and therefore unrealized gains and losses related to changes in the fair value of our interest rate swaps are deferred in other comprehensive income and realized gains and losses are recognized in interest expense when the forecasted transaction occurs.

Fair Value of Financial Instruments

We include fair value information in the notes to consolidated financial statements when the fair value of our financial instruments is different from the book value. We believe that the book value of our cash and cash equivalents, receivables, accounts payable, accrued liabilities and long-term debt materially approximates fair value due to the short-term nature and the terms of these instruments.

Income Taxes

We use the liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements.

Deferred Financing Costs

We defer and amortize debt issuance costs and debt premiums or discounts over the scheduled maturity of the debt utilizing the effective interest method.

Share-Based Compensation

Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) (“SFAS No. 123(R)”), *Share-Based Payment.* The adoption had no impact on our financial statements. In accordance with SFAS No. 123(R), compensation cost is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award.

Earnings Per Share

Basic earnings per share was calculated by dividing net income applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings per share incorporates the potential dilutive impact of preferred stock and nonvested restricted stock outstanding during the periods presented.

Recent Accounting Developments

In July 2006, the Financial Accounting Standards Board (“FASB”) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of SFAS No. 109*, (“FIN 48”), which clarifies the accounting for uncertainty in income taxes recognized in a company’s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It 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. Adoption of FIN 48 is not expected to have a material effect on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value as that term is used in many accounting pronouncements, establishes a framework for measuring the fair value of assets and liabilities as already required by generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently evaluating the impact that SFAS No. 157 may have on our consolidated financial statements.

2. Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations*, requires that an asset retirement obligation (“ARO”) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The ARO is recorded at fair value and accretion expense is recognized over time as the discounted liability is accreted to our expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at our credit-adjusted risk-free interest rate.

The following is a reconciliation of our asset retirement obligation liability as of December 31, 2006 and 2005 (in millions).

	2006	2005
Asset retirement obligation, beginning of period	$152.3	$142.4
Liabilities settled	(24.5)	(17.9)
Accretion of discount	12.5	9.1
Liabilities assumed through acquisition	143.6	2.6
Liabilities incurred	4.2	3.3
Revisions of estimated liabilities	26.0	12.8
Asset retirement obligation, end of period	$314.1	$152.3

3. Restricted Deposits

Restricted deposits as of December 31, 2006 and 2005 consisted of funds escrowed for the future plugging and abandonment of certain oil and gas properties. We are currently not obligated to contribute additional amounts to these escrowed accounts.

4. Significant Acquisition

On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger. We own the surviving entity, which is the successor to substantially all of Kerr-McGee's interests in Gulf of Mexico conventional shelf properties. The properties acquired include interests in approximately 100 fields on 242 offshore blocks (including 88 undeveloped blocks) spreading across the Western, Central and Eastern U.S. Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, additional debt and proceeds from the issuance of our common stock.

This acquisition was accounted for as a purchase, and accordingly, the results of operations are included in our consolidated statements of income from the date of acquisition. The purchase price was allocated to the acquired assets and assumed liabilities based on their estimated fair values at the date of acquisition. The final purchase price is subject to post-closing adjustments pursuant to and in accordance with the Merger Agreement. The following summarizes the estimated fair values of assets acquired and liabilities assumed at closing (in thousands).

Purchase price:	
Cash paid, including transaction costs	$1,061,769
Allocation of purchase price:	
Acquired assets:	
Proved oil and gas properties	$ 813,670
Unproved oil and gas properties	391,740
Assumed liabilities:	
Asset retirement obligations	(143,641)
	$1,061,769

The following unaudited pro forma data illustrates the effect on our historical results of operations as if the merger transaction, an offering of the Company's common stock to provide funds for the merger transaction and borrowings under the Company's credit agreement to partially fund the merger had occurred at the beginning of each period presented. The pro forma data is a result of adjusting our statements of income for the years ended December 31, 2006 and 2005 for the pre-acquisition revenues and direct operating expenses of the Kerr-McGee acquired properties. Also taken into consideration are increased depreciation, depletion, amortization and accretion resulting from the allocation of fair value to the oil and gas properties acquired and the asset retirement obligations assumed, increased general and administrative expenses due to the need for additional personnel to manage the Company after the acquisition and increased interest expense on acquisition debt. The pro forma adjustments include estimates and assumptions based on currently available information. The pro forma data does not necessarily reflect the actual operating results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Year Ended December 31,			
	2006		2005	
	Historical	Pro Forma (Unaudited)	Historical	Pro Forma (Unaudited)
Revenues	$800,466	$1,147,455	$585,136	$1,147,200
Net income	199,104	278,366	189,023	338,422
Earnings per share:				
Basic	$ 2.84	$ 3.67	$ 2.91	$ 4.53
Diluted	$ 2.84	$ 3.67	$ 2.87	$ 4.47

5. Equity Structure and Transactions

On October 26, 2004, the board of directors declared a 6.669173211-for-1 split of our common stock, which was payable on November 30, 2004 in the form of a dividend to shareholders of record on November 15, 2004. The total authorized number of shares of common stock was increased to 118.33 million. For all periods presented, the share and per share data reflected in the consolidated financial statements have been adjusted to give effect to the common stock split.

On January 28, 2005, certain shareholders of our common stock sold 12,655,263 shares pursuant to a registration statement that we filed with the SEC at an initial public offering price of $19.00 per share. The Company did not receive any of the net proceeds from this offering; however, during the years ended December 31, 2005 and 2004, we did incur costs associated with the offering of $0.9 million and $1.5 million, respectively, which are included in general and administrative expenses. Our common stock is listed and principally traded on the New York Stock Exchange under the symbol "WTI".

In connection with our initial public offering in January 2005, all two million shares of the Company's Preferred Stock were converted into a total of 13,338,350 shares of our common stock. As of December 31, 2006 and 2005, the Company had two million shares of preferred stock authorized with a par value of $0.00001 per share and no shares issued and outstanding.

In July 2006 the Company completed an additional equity offering of 8,500,000 shares of its common stock at an offering price of $32.50 per share. The Underwriting Agreement also included a 30-day option that allowed the underwriters to purchase up to an additional 1,275,000 shares at the offering price, less underwriting discounts and commissions. In August 2006 the over-allotment option was exercised in full. Net proceeds generated by the offering and the exercise of the over-allotment option were approximately $307.0 million after underwriting discounts and commissions of approximately $9.5 million and legal, accounting, printing and various other fees of approximately $1.2 million. The net proceeds from the equity offering and the exercise of the over-allotment option were used in connection with the funding of the Kerr-McGee transaction.

On March 7, 2007, the Company's board of directors declared a cash dividend of $0.03 per share of common stock, payable on May 1, 2007 to shareholders of record on April 13, 2007.

6. Long-Term Debt

On May 26, 2006, we entered into a new credit agreement principally in connection with the funding of the Kerr-McGee transaction. The new credit agreement became effective upon closing of the Kerr-McGee transaction in August 2006 and replaced our existing credit agreement dated March 15, 2005.

Our initial availability under the new credit agreement was $987.5 million. The credit agreement provides for (1) a revolving loan with an initial availability of $300.0 million, (2) a Tranche A term loan in the amount of $387.5 million and (3) a Tranche B term loan in the amount of $300.0 million. The amount available under the revolving loan is subject to redetermination on March 1 and September 1 of each year commencing September 1, 2007. Additionally, the agreement provides for the availability of letters of credit for up to $90.0 million, provided however, that its usage is subject to availability under the revolving loan.

Interest accrues either (1) at the higher of the Prime Rate, or the Federal Funds Rate plus 0.50%, plus a margin which varies from 0.0% to 1.75% depending upon the loan or (2) to the extent any loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate plus a margin that varies from 1.25% to 2.75% depending upon the loan. The Tranche A and Tranche B term loans are payable in installments and mature fifteen months from initial funding and on the fourth anniversary of initial funding, respectively. The revolving loan matures on the third anniversary of initial funding. The effective interest rates on the Tranche A, Tranche B and revolving loans were 13.5%, 8.6% and 10.6%, respectively, at December 31, 2006.

Substantially all of our oil and gas properties are pledged as collateral under our bank credit agreement. In addition, our credit agreement contains covenants that restrict the payment of cash dividends to a maximum of $30.0 million per year, borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. We are required to maintain interest rate hedging contracts with respect to at least 50% of the aggregate principal amount outstanding of the Tranche A and Tranche B term loans at all times, as well as maintain our commodity derivatives (see Note 7). We are also subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio beginning with the quarter ending on March 31, 2007, a minimum interest coverage ratio, a minimum asset coverage ratio and a maximum leverage ratio. We were in compliance with all applicable covenants as of December 31, 2006.

As of December 31, 2006 and 2005 our long-term debt was as follows (in thousands):

	December 31,	
	2006	2005
Revolving loan facility, due August 2009	$ 122,000	$40,000
Tranche A term loan facility, net of unamortized discount of $4,583, due November 2007	270,417	—
Tranche B term loan facility, net of unamortized discount of $7,420, due August 2010	292,580	—
Total long-term debt	684,997	40,000
Current maturities of long-term debt (1)	(271,380)	—
Long-term debt, less current maturities	$ 413,617	$40,000

(1) Includes $275.0 million related to Tranche A and $1.5 million related to Tranche B, net of unamortized discount of $5.1 million.

At December 31, 2006 we did not have any letters of credit outstanding. At December 31, 2005 we had $0.3 million of letters of credit outstanding. Aggregate annual maturities of long-term debt as of December 31, 2006 are as follows (in millions): 2007–$276.5; 2008–$3.0; 2009–$125.0; 2010–$292.5. All of the Company's long-term debt is due by August 2010.

7. Derivative Financial Instruments

We account for our derivative contracts in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 133, as amended, requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Additionally, the statement requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is entered into. Counterparties to our derivative contracts expose the Company to credit loss in the event of nonperformance; however, we do not anticipate nonperformance by the counterparties.

Commodity Derivatives

In January 2006, we entered into commodity swap and option contracts in connection with the anticipated financing related to the transaction with Kerr-McGee. While these contracts are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income from favorable price movements. Changes in the fair value of our commodity derivative contracts are recognized currently in earnings.

During the year ended December 31, 2006, we recorded an unrealized gain of $13.5 million related to our open derivative contracts and we recorded a realized gain of $10.7 million related to settlements of our commodity derivatives. At December 31, 2006, $13.5 million was included in prepaid expenses and other assets and $3.5 million was included in other assets related to our open commodity derivatives.

As of December 31, 2006, our open commodity derivatives were as follows:

Collars

Type	Commodity	Effective Date	Termination Date	Notional Quantity	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling	Fair Value (in thousands)
Funded	Natural Gas	1/1/2007	12/31/2007	8,016,000 MMBtu	$ 7.76	$16.80	$10,950
Zero Cost	Oil	1/1/2007	12/31/2007	1,569,500 Bbls	61.68	76.40	2,511
Funded	Natural Gas	1/1/2008	12/31/2008	5,124,000 MMBtu	7.31	15.80	3,413
Zero Cost	Oil	1/1/2008	12/31/2008	1,024,800 Bbls	60.00	74.50	73

Interest Rate Swaps

In connection with the Kerr-McGee merger transaction, our credit agreement required that we enter into interest rate swap contracts. In August 2006, we entered into two interest rate swaps, which serve to hedge the risk associated with the variable LIBOR rates used to reset the floating rates of our Tranche A and Tranche B term loans. For each of the interest rate swaps, we pay the counterparty the equivalent of a fixed interest payment on 50% of the aggregate outstanding principal balance of the Tranche A and Tranche B term loans and receive from the counterparty the equivalent of a floating interest payment based on a 3-month LIBOR rate calculated on the same notional amount. All interest rate swap payments are made quarterly and the LIBOR is determined in advance of each interest period. The fixed interest rates of the swaps related to the Tranche A and Tranche B term loans are 5.41% and 5.16%, respectively. The effective interest rates on the Tranche A and Tranche B loans were 13.5% and 8.6%, respectively, at December 31, 2006. These swaps have been determined to be highly effective as it relates to the variability in the LIBOR interest rate and, therefore, qualify, and are designated by management, as cash flow hedges under SFAS No. 133.

At December 31, 2006, a $0.6 million, net of income tax, unrealized loss on hedging activity is included in accumulated other comprehensive loss resulting from the decrease in fair value of the interest rate swaps. Realized gains or losses on the swaps are recorded to interest expense in future periods. The actual amounts that will be recorded to our consolidated statement of income could vary from this estimated amount as a result of future changes in interest rates. For the year ended December 31, 2006, no amount was recognized in earnings due to ineffectiveness related to our interest rate swaps.

8. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities were as follows (in thousands):

	December 31,	
	2006	2005
Deferred tax liabilities:		
Oil and gas properties and equipment	$239,051	$135,298
Other	10,336	—
Total deferred tax liabilities	249,387	135,298
Deferred tax assets:		
Alternative minimum tax credits	(5,834)	—
Other	(2,822)	(903)
Net deferred tax liabilities	$240,731	$134,395

As of December 31, 2006, the Company has $5.8 million of alternative minimum tax credits that carry forward indefinitely.

Significant components of income tax expense were as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Current	$ 605	$ 57,037	$39,819
Deferred	106,645	43,966	40,189
	$107,250	$101,003	$80,008

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to our income tax expense is as follows (in thousands):

	Year Ended December 31,					
	2006		2005		2004	
Income tax expense at the federal statutory rate	$107,224	35.0%	$101,509	35.0%	$80,322	35.0%
Permanent and other	26	0.0%	(506)	(0.2)%	(314)	(0.0)%
	$107,250	35.0%	$101,003	34.8%	$80,008	35.0%

The Katrina Emergency Tax Relief Act of 2005, signed on September 23, 2005, postponed tax deadlines with a due date falling on or after August 29, 2005 until February 28, 2006 for taxpayers affected by Hurricane

Katrina. On February 17 and August 25, 2006, the Internal Revenue Service further postponed tax deadlines with a due date falling on or after August 29, 2005 until August 28 and October 16, 2006, respectively, for taxpayers affected by Hurricane Katrina. Consequently, our estimated federal income tax payments due in the third and fourth quarters of 2005 were paid on October 16, 2006 and totaled $33.5 million.

9. Commitments

We have operating lease agreements for office space, which terminate in December 2011. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2006 are as follows (in millions): $2.0–2007, $1.9–2008, $1.2–2009, $1.2–2010, $1.2–2011, $0.0–Thereafter.

Total rent expense was approximately $1.4 million, $0.8 million and $0.9 million during the years ended December 31, 2006, 2005 and 2004, respectively. Due to damage to our office in Metairie, Louisiana caused by Hurricane Katrina in August 2005, rent expense for 2005 was reduced by approximately $0.2 million.

10. Contingent Liabilities

The Company is a party to various pending or threatened claims and complaints seeking damages or other remedies concerning its commercial operations and other matters. Some of these claims relate to matters occurring prior to its acquisition of properties and some relate to properties it has sold. In certain cases, the Company is entitled to indemnification from the sellers of properties and in other cases, it has indemnified the buyers of properties from it. Although the Company can give no assurance about the outcome of pending legal and administrative proceedings and the effect such outcomes may have on it, management believes that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on its consolidated financial position, results of operations or liquidity.

11. Insurance Receivables

As of December 31, 2006 we have incurred $10.8 million of development costs and $85.9 million of production costs (consisting primarily of repairs and maintenance and well control expenses), net to our interest, to remediate damage caused by Hurricanes Katrina and Rita which we reclassified to insurance receivables, excluding our deductibles. In 2006 we received reimbursements of our claims totaling $21.9 million. Included in insurance receivables at December 31, 2006 is $75.2 million, which represents the estimated reimbursable hurricane remediation costs incurred in excess of our deductibles, plus an insurance claim to recover reimbursable drilling costs on a well at Green Canyon 82 which experienced uncontrollable water flow in the second quarter of 2006.

In March 2007, the Company completed written settlement agreements with its insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as the claim related to Green Canyon 82. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company will receive additional proceeds of $73.3 million, currently expected in March 2007. Reimbursements totaling $78.1 million that will be received in 2007 exceeds our insurance receivables at December 31, 2006 by $2.9 million. Such amount will be used to offset hurricane remediation expenses incurred in 2007. We estimate that we could spend between $15 million to $20 million in 2007 to repair damage to our facilities caused by Hurricanes Katrina and Rita, the majority of which will not be covered by insurance. Uninsured expenditures will be recorded to development costs or production costs as incurred, based on the nature of the expenditure. The timing of future repairs will be affected by equipment availability, design and remediation planning and permitting.

12. Long-Term Incentive Compensation

In 2003, we implemented a long-term incentive compensation plan, the purpose of which is to reward certain key employees for exceptional performance. Effective April 15, 2004, we replaced this plan with a new long-term incentive compensation plan (the "Plan"). The key metrics for determining awards, which may be in the form of stock options, stock appreciation rights, restricted stock or performance shares, are return on equity, lease operating cost containment, general and administrative cost containment, reserve replacement and growth, reserve replacement cost and increased production. The Plan may be terminated by executive management or the board of directors at any time without incurring additional obligations for grants.

In 2005, we amended the Plan with the W&T Offshore, Inc. 2005 Annual Incentive Plan (the "2005 Plan"). The 2005 Plan includes all employees of the Company except those executive officers (including our Chief Executive Officer and our Secretary) who, by written agreement, have elected not to participate. Under the 2005 Plan, eligible employees earn cash bonuses and awards of restricted stock from a bonus pool. The bonus pool equates to a maximum value of five percent of adjusted pre-tax income as determined by the Compensation Committee of the board of directors. Awards of restricted stock are issued pursuant to, and are subject to, the terms of both the 2005 Plan and the Plan.

Bonuses under the 2005 Plan consist of a general bonus and an extraordinary performance bonus. Each category of bonus includes cash and restricted stock and will be awarded to an employee based on pre-determined percentages of that employee's base salary. However, the extraordinary performance bonus will be paid only if the Company achieves certain performance goals, which may be adjusted by the Compensation Committee for extraordinary or unusual items or events. Shares of restricted stock awarded under the 2005 Plan vest in three equal annual installments with the first such installment vesting on December 31 of the year in which the bonus is paid. Only those eligible employees who are employed by the Company on the date a bonus is paid under the 2005 Plan will be entitled to receive such bonus.

2005 Bonus

In accordance with the 2005 Plan, in March 2006 our board of directors approved payment of a general bonus and an extraordinary performance bonus for 2005. Although not all of the performance measures for the extraordinary performance bonus were met, our board determined that substantially all of the performance measures would have been met in 2005 if not for the effects of Hurricanes Katrina and Rita. As such, in March 2006, our board awarded a 2005 extraordinary performance bonus with an aggregate value of $3.4 million to eligible employees.

The cash bonus for 2005 (general bonus and extraordinary performance bonus) was paid in March 2006 and totaled $4.2 million. Of this amount, $2.2 million was expensed in 2005, $1.7 million was expensed in the first quarter of 2006 and the remainder was billed to partners under joint operating agreements.

The share-based portion of the 2005 bonus (general bonus and extraordinary performance bonus) consisted of 160,377 restricted shares of our common stock. The associated compensation expense, less an allowance for estimated forfeitures, is being recognized over the requisite service period in accordance with SFAS No. 123(R) (see Note 13).

2006 Bonus

In accordance with the 2005 Plan, eligible employees will be entitled to receive cash bonuses and awards of restricted stock from a bonus pool limited to five percent of adjusted pre-tax income for 2006. Shares of restricted stock awarded as incentive compensation for performance in 2006 will vest in three equal annual installments on December 31, 2007, 2008 and 2009. During the year ended December 31, 2006, we expensed $4.7 million related to the general bonus and $1.7 million related to the extraordinary performance bonus for 2006.

13. Share-Based Compensation

Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), *Share-Based Payment*, using the modified prospective transition method. SFAS No. 123(R) supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and revises guidance in SFAS No. 123, *Accounting for Stock-Based Compensation*. Under the modified prospective transition method, we are required to recognize compensation cost for share-based payments to employees over the period during which an employee is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant. Also, measurement and recognition of compensation cost for awards that were granted prior to, but not vested as of, the date of adoption should be based on their grant-date fair values. The new standard requires us to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that actually vest. A cumulative effect of a change in accounting principle is required upon adoption to the extent that forfeitures were not estimated on share-based payments awarded prior to January 1, 2006 and that were unvested on that date.

Historically, all of our share-based payments consisted of awards of unrestricted and restricted stock and were measured at their fair values on the dates of grant. As of January 1, 2006, the date we adopted SFAS No. 123(R), there were a total of 9,251 shares of restricted stock that had not vested and these shares were held by an executive officer of the Company. We estimated that the probability of forfeiture of these shares on the date of adopting SFAS No. 123(R) was remote; therefore, an adjustment to record a cumulative effect of a change in accounting principle was not required.

The Company issues new shares in connection with its share-based payment plans. Restricted shares are subject to forfeiture restrictions and cannot be sold, transferred or disposed of during the restriction period. The holders of restricted shares generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares.

At December 31, 2006, there were 2,159,152 shares of common stock available for award under our share-based payment plans. A summary of share activity pursuant to our share-based payment plans for the year ended December 31, 2006, is as follows:

	Restricted Shares	Weighted Average Grant Date Fair Value
Nonvested at January 1, 2006	9,251	$32.43
Granted	165,732	$37.30
Vested	(51,598)	$37.22
Forfeited	(20,525)	$35.03
Nonvested at December 31, 2006	102,860	$37.35

During the year ended December 31, 2006, a total of 161,784 shares of our common stock were granted to employees pursuant to our share-based payment plans, all of which were in the form of restricted stock. Of those shares, 51,598 shares vested on December 31, 2006 and the remainder will vest in equal increments on December 31, 2007 and 2008. The weighted-average fair value of the shares that vested in 2006 was $1.6 million, based on the closing prices on the dates of vesting.

Also in 2006, our non-employee directors were granted a total of 3,948 restricted shares of our common stock, with restrictions lapsing with respect to one-third of the shares on each of the first, second, and third anniversaries from the date of grant.

During 2005, we issued 29,851 shares of common stock to employees pursuant to our share-based payment plans, of which 9,251 shares were restricted and 20,600 shares were unrestricted. In 2004 we issued 95,118 shares of common stock to employees pursuant to our share-based payment plans, all of which were unrestricted. There were no restricted shares that vested during the years ended December 31, 2005 and 2004.

The weighted average grant date fair value of shares granted under our share-based payment arrangements during the years ended December 31, 2006, 2005 and 2004 was $6.2 million, $0.7 million and $0.4 million, respectively. Total compensation expense under share-based payment arrangements was $2.4 million, $0.4 million and $0.4 million during the years ended December 31, 2006, 2005 and 2004. As of December 31, 2006, there was $2.8 million of total unrecognized compensation expense related to restricted shares, which is expected to be recognized between 2007 and May 2009.

14. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the Internal Revenue Code (the "401(k) Plan"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2006, 2005 and 2004, the Company's matching contribution was 100% of each participant's contribution up to a maximum of 5% of the participant's compensation, subject to limitations imposed by the Internal Revenue Service. Our expenses relating to the 401(k) Plan were approximately $1.1 million, $0.7 million and $0.5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

15. Earnings Per Share

Basic earnings per share was calculated by dividing net income applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings per share incorporates the potential dilutive impact of preferred stock and nonvested restricted stock outstanding during the periods presented. In connection with our initial public offering in January 2005, all 2,000,000 shares of the Company's preferred stock were converted into a total of 13,338,350 shares of common stock.

The reconciliation of basic and diluted weighted average shares outstanding and earnings per share is as follows (in thousands, except per share amounts):

	Year Ended December 31,		
	2006	2005	2004
Net income applicable to common shares	$199,104	$189,023	$148,582
Add preferred stock dividends	—	—	900
Adjusted net income applicable to common Shares	$199,104	$189,023	$149,482
Weighted average number of common shares (basic)	70,177	64,982	52,604
Weighted average common shares assumed issued upon conversion of the preferred stock	—	989	13,338
Weighted average nonvested common shares	40	—	—
Weighted average number of common shares (diluted)	70,217	65,971	65,942
Earnings per share:			
Basic	$ 2.84	$ 2.91	$ 2.82
Diluted	$ 2.84	$ 2.87	$ 2.27

16. Comprehensive Income

Our comprehensive income for the periods indicated is as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Net income	$199,104	$189,023	$149,482
Interest rate swap settlements reclassified to income, net of income tax	67	—	—
Change in the fair value of open interest rate swaps, net of income tax	(640)	—	—
Comprehensive income	$198,531	$189,023	$149,482

17. Related Party Transactions

On February 2, 2005, the Company closed its initial public offering of common stock. Four executive officers of the Company, Messrs. Krohn, Lea, Slattery and Durrant, sold a total of 2,666,442 shares of common stock in the initial public offering. Funds managed by Jefferies Capital Partners, with which two of the Company's directors, Messrs. Katz and Luikart, are associated, sold a total of 9,988,821 shares of common stock in the initial public offering. The Company paid all legal, accounting, engineering, printing and certain other expenses and all registration and listing fees associated with the initial public offering. These expenses and fees aggregated approximately $2.5 million. The Company also agreed to indemnify and hold harmless the underwriters in the initial public offering for certain liabilities in connection with the offering.

We received approximately $0.1 million for providing management services to W&T Offshore, LLC ("W&T LLC") during each of the years of 2006, 2005 and 2004, under the terms of a management agreement we executed with W&T LLC. W&T LLC is controlled by Tracy W. Krohn and J.F. Freel, our two largest common shareholders, who are also officers and directors. These fees are recorded as a direct reduction of general and administrative expenses. The management agreement with W&T LLC has been terminated effective December 31, 2006.

The grandson of J.F. Freel, a director and our corporate Secretary, is employed by an insurance agency that arranged as a broker certain insurance coverage for the Company. We have been informed by Mr. Freel's grandson that personal commissions earned by the grandson for arranging such coverage through his employer totaled approximately $247,000, $122,000 and $69,000 in 2006, 2005 and 2004, respectively. Effective January, 2007 our insurance coverage is arranged by another broker that is not affiliated with this individual.

Brooke Companies, Inc. provides personnel to fill temporary and permanent staffing needs of the Company from time to time. Susan Krohn, the wife of Tracy W. Krohn, owns 100% of Brooke Companies. Brooke Companies currently provides staffing services to our Company and we expect that it will continue to provide those services for the foreseeable future. During the years ended December 31, 2006, 2005 and 2004, the Company paid Brooke Companies approximately $0.5 million, $0.2 million and $0.4 million, respectively.

During each of the years 2006 and 2005, we paid approximately $0.4 million to Adams and Reese LLP for legal services. Virginia Boulet, who serves as special counsel to Adams and Reese LLP, was appointed to our board of directors on March 25, 2005.

During each of the years 2005 and 2004, we paid approximately $0.1 million to Schully, Roberts, Slattery & Marino for legal services. Gerald F. Slattery, Jr., the brother of one of our executive officers, is a shareholder in that firm.

As part of our relocation program for employees moving from Louisiana to Texas, the Company agreed to purchase their homes in Louisiana that had been actively marketed and had been for sale for a period greater than 90 days. The purchase price of an employee's home was negotiable and based on a reasonable appraised value. During the year ended December 31, 2006, the Company purchased homes from two of our vice presidents pursuant to the relocation program for a total of approximately $2.7 million pursuant to the relocation program. These homes were subsequently sold for a total of approximately $2.3 million, resulting in a pre-tax loss of $0.4 million which is included in general and administrative expenses for the year ended December 31, 2006.

18. Supplemental Cash Flow Information

The following reflects our supplemental cash flow information (in thousands).

	Year Ended December 31,		
	2006	2005	2004
Cash flow information:			
Cash paid for interest, net of interest capitalized of $13,238 in 2006	$ 6,362	$ 791	$ 1,692
Cash paid for income taxes, net of refunds	47,993	17,969	65,229

19. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2006 and 2005 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2006				
Revenues	$156,854	$165,796	$213,432	$264,384
Operating income	84,342	57,306	105,773	70,194
Net income	55,831	38,465	66,701	38,107
Earnings per common share: (1)				
Basic	0.85	0.58	0.92	0.50
Diluted	0.85	0.58	0.91	0.50
Year Ended December 31, 2005				
Revenues	$129,072	$149,779	$153,425	$152,860
Operating income	60,245	71,091	80,518	76,571
Net income	39,282	45,782	53,102	50,857
Earnings per common share: (1)				
Basic	0.63	0.69	0.80	0.77
Diluted	0.60	0.69	0.80	0.77

(1) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share because each quarterly calculation is based on the income for that quarter and the weighted average number of shares outstanding during that quarter.

20. Supplemental Oil and Gas Disclosures—UNAUDITED

Capitalized Costs

Net capitalized costs related to our oil and natural gas producing activities are as follows (in millions):

	December 31,		
	2006	2005	2004
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 2,822.3	$1,389.5	$1081.9
Unproved oil and natural gas properties and equipment	474.9	90.3	58.9
Accumulated depreciation, depletion and amortization	(1,038.3)	(714.6)	(541.1)
	$ 2,258.9	$ 765.2	$ 599.7

As of December 31, 2006, $308.2 million of costs were excluded from amortizable capital costs, consisting of $295.0 million of acquisition costs and $13.2 million of capitalized interest, all of which were incurred in 2006. Costs not subject to amortization relate to unproved properties which are excluded from amortizable capital costs until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. Subject to industry conditions, evaluation of most of these properties is expected to be completed within three to seven years.

Costs Incurred In Oil and Gas Property Acquisition, Exploration and Development Activities

The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2006, 2005, and 2004 (in millions):

	Year Ended December 31,		
	2006	2005	2004
Costs incurred (1):			
Proved property acquisitions	$ 841.0	$ 19.5	$ 37.7
Development	330.9	189.9	100.5
Exploration	252.9	122.9	154.9
Unproved property acquisitions	399.7	9.4	7.9
	$1,824.5	$341.7	$301.0

(1) Includes $173.8 million, $18.7 million and $18.5 million for asset retirement obligations incurred during the years ended December 31, 2006, 2005 and 2004, respectively.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion expense per Mcfe of products sold.

	Year Ended December 31,		
	2006	2005	2004
Depreciation, depletion, amortization and accretion per Mcfe	$3.40	$2.59	$2.00

Oil and Gas Reserve Information

Our net proved oil and gas reserves at December 31, 2006, 2005 and 2004 have been estimated by our independent petroleum consultant in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates, and exclude royalties and interests owned by others.

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available.

The following sets forth our estimated quantities of net proved and proved developed oil (including condensate) and natural gas reserves, all of which are located onshore in the continental United States and offshore in the Gulf of Mexico.

	Oil (MBbls)	Natural Gas (MMcf)	Total Oil and Natural Gas (MMcfe) (1)
Proved reserves as of January 1, 2004	35,602	231,061	444,675
Revisions of previous estimates	2,351	6,770	20,875
Extensions, discoveries and other additions	4,582	37,732	65,224
Purchase of minerals in place	2,294	5,464	19,228
Sales of reserves	(1)	(106)	(112)
Production	(4,847)	(53,348)	(82,432)
Proved reserves as of December 31, 2004	39,981	227,573	467,458
Revisions of previous estimates	2,456	5,546	20,287
Extensions, discoveries and other additions	5,920	25,120	60,640
Purchase of minerals in place	1,665	4,229	14,219
Production	(4,085)	(46,548)	(71,060)
Proved reserves as of December 31, 2005	45,937	215,920	491,544
Revisions of previous estimates	(1,242)	(5,692)	(13,149)
Extensions, discoveries and other additions	7,255	65,759	109,289
Purchase of minerals in place	10,165	185,697	246,686
Production	(6,456)	(60,447)	(99,181)
Proved reserves as of December 31, 2006	55,659	401,237	735,189
Year-end proved developed reserves:			
2006	31,325	290,913	478,863
2005	24,773	169,995	318,633
2004	20,311	168,260	290,126

(1) One million cubic feet equivalent (MMcfe) is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and gas reserves together with changes therein, as defined by the FASB, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the consolidated balance sheet at December 31, 2006, 2005 and 2004 in accordance with SFAS No. 143. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on period-end prices. The period-end prices adjusted by lease for quality, transportation fees, energy content, and regional price differentials related to proved reserves of natural gas approximated $5.40, $10.15 and $6.31 per Mcf and for oil were $52.79, $54.55 and $39.05 per barrel at December 31, 2006, 2005 and 2004, respectively. Future production and development costs are based on current costs with no escalations. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on a 10% annual discount rate.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and gas reserves. These estimates reflect proved reserves only and ignore, among other things, changes in prices and costs, revenues that could result from probable reserves, which could become proved reserves in 2007 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$5,106,245	$ 4,697,926	$2,998,214
Future costs:			
Production	(693,633)	(504,741)	(467,784)
Development	(719,634)	(433,572)	(277,905)
Dismantlement and abandonment	(466,244)	(220,943)	(204,626)
Future net cash flows before income taxes	3,226,734	3,538,670	2,047,899
Future income taxes	(790,207)	(1,146,073)	(646,418)
Future net cash inflows before 10% discount	2,436,527	2,392,597	1,401,481
10% annual discount factor	(744,654)	(796,151)	(426,693)
	$1,691,873	$ 1,596,446	$ 974,788

	Year Ended December 31,		
	2006	2005	2004
Changes in Standardized Measure			
Standardized measure, beginning of year	$1,596,446	$ 974,788	$ 760,939
Sales and transfers of oil and gas produced, net of production costs	(672,999)	(500,676)	(421,142)
Net changes in price, net of future production costs	(652,557)	900,738	256,315
Extensions and discoveries, net of future production and development costs	286,028	224,965	257,206
Changes in estimated future development costs	(65,614)	(143,296)	(76,704)
Previously estimated development costs incurred	146,046	192,475	103,653
Revisions of quantity estimates	(59,144)	113,390	78,371
Accretion of discount	217,772	129,387	100,580
Net change in income taxes	216,008	(315,100)	(94,649)
Purchases of reserves in-place	720,365	91,306	58,152
Sales of reserves in-place	—	—	(524)
Changes in production rates due to timing and other	(40,478)	(71,531)	(47,409)
Net increase in standardized measure	95,427	621,658	213,849
Standardized measure, end of year	$1,691,873	$ 1,596,446	$ 974,788

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

None

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of December 31, 2006 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Annual Report on Internal Control Over Financial Reporting

See Item 8 "*Management's Report on Internal Control over Financial Reporting*."

Attestation Report of the Registered Public Accounting Firm

See Item 8 "*Report of Independent Registered Public Accounting Firm.*"

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control 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 by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth in Item 4 of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Documents filed as a part of this report

1. Financial Statements. See "Index to Consolidated Financial Statements" in Part II, Item 8 of this Form 10-K.

All schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

2. Exhibits:

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, dated February 24, 2006)
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
4.1	Specimen Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.1	Credit Agreement, dated March 15, 2005, by and between W&T Offshore, Inc., a Texas Corporation, and Toronto Dominion (Texas), LLC, TD Securities (USA), LLC, JP Morgan Chase Bank, N.A. and Fortis Capital Corp., Harris Nesbitt Financing, Inc. and Bank of Scotland, Natexis Banques Populaires, and certain additional financial institutions. (Incorporated by reference from the Company's Current Report filed on Form 8-K, dated March 16, 2005)
10.2	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors and W. Reid Lea. (Incorporated by reference to Exhibit 10.8 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.3	Employment Agreement dated April 21, 2004, by and between Tracy W. Krohn and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.9 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.4	Employment Agreement dated October 20, 2005, by and between Reid Lea and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, dated October 26, 2006)
10.5	Employment Agreement dated October 20, 2005, by and between Joseph Slattery and the Company. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, dated October 26, 2005)
10.6	Employment Agreement dated October 20, 2005, by and between Jeff Durrant and the Company. (Incorporated by reference to Exhibit 10.13 of the Company's Current Report on Form 8-K, dated October 26, 2005)
10.7	Indemnification and Hold Harmless Agreement dated March 25, 2005, by and between Virginia Boulet and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, dated March 25, 2005)
10.8	Indemnification and Hold Harmless Agreement dated January 20, 2006, by and between S. James Nelson, Jr. and the Company. (Incorporated by reference to Exhibit 10.10 of the Company's Annual Report on Form 10-K filed on March 31, 2006)

Exhibit Number	Description
10.9	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.10	W&T Offshore, Inc. Long-Term Incentive Compensation Plan (2003). (Incorporated by reference to Exhibit 10.13 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.11	W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.10 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.12	W&T Offshore, Inc. 2005 Annual Incentive Plan. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, dated October 27, 2005)
10.13	Exchange Agreement dated November 25, 2002, by and among W&T Offshore, Inc., and ING Furman Selz Investors III L.P., ING Barings U.S. Leveraged Equity Plan LLC, ING Barings Global Leveraged Equity Plan Ltd. and Jefferies & Company, Inc. (Incorporated by reference to Exhibit 10.12 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.14	Agreement and Plan of Merger among Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil & Gas (Shelf) LLC, W&T Offshore, Inc., and W&T Energy V, LLC, effective October 1, 2005. (Incorporated by reference to Exhibit 99.1 of the Company's Current Report on Form 8-K, dated January 27, 2006)
10.15	Employment Agreement dated September 28, 2005 by and between William W. Talafuse and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, dated March 29, 2006)
10.16	Indemnification and Hold Harmless Agreement dated March 29, 2006, by and between William W. Talafuse and the Company. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, dated March 29, 2006)
10.17	Third Amended and Restated Credit Agreement dated May 26, 2006; First Amendment to Third Amended and Restated Credit Agreement dated June 9, 2006; and Second Amendment to Third Amended and Restated Credit Agreement dated July 27, 2006. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on August 7, 2006)
10.18	Employment Agreement dated July 5, 2006, by and between the W&T Offshore, Inc. and Stephen L. Schroeder. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on July 12, 2006)
10.19	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006 (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on July 12, 2006)
10.20	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and Reid Lea effective September 28, 2005. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K filed on July 12, 2006)
10.21	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and Joseph Slattery effective September 28, 2005. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K filed on July 12, 2006)
10.22	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and Jeff Durrant effective September 28, 2005. (Incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K filed on July 12, 2006)
10.23	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and William W. Talafuse effective September 28, 2005. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on July 21, 2006)

Exhibit Number	Description
10.24	Employment Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007 (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on February 26, 2007)
10.25	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007 (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on February 26, 2007)
14	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company's Current Report on Form 8-K, dated November 17, 2005)
21*	Subsidiaries of the Registrant.
23.1*	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2*	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.

* Filed or furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that are used in this report.

Acquisitions. Refers to acquisitions, mergers or exercise of preferential rights of purchase.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Conventional shelf well. A well drilled in water depths less than 500 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet.

Deepwater. Water depths below 500 feet in the Gulf of Mexico.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or other hydrocarbon.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil condensate or natural gas liquids.

MMS. The Minerals Management Service, a bureau in the U.S. Department of the Interior, is the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf (OCS).

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Oil. Crude oil, condensate and natural gas liquids.

OCS block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the MMS.

Productive well. A well that is found to be capable of producing hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved. The SEC provides a complete definition of proved developed reserves in Rule 4-10(a)(3) of Regulation S-X.

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 demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and cost 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 on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved oil and gas 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir. The SEC provides a complete definition of proved undeveloped reserves in Rule 4-10(a)(4) of Regulation S-X.

PV-10 value. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

Recompletion. The completion for production of an existing well bore in another formation from that which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

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, on March 9, 2007.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President and Chief Financial 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 indicated on March 9, 2007.

/s/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)
/s/ JOHN D. GIBBONS **John D. Gibbons**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ WILLIAM W. TALAFUSE **William W. Talafuse**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ VIRGINIA BOULET **Virginia Boulet**	Director
/s/ J.F. FREEL **J.F. Freel**	Secretary and Director
/s/ STUART B. KATZ **Stuart B. Katz**	Director
/s/ JAMES L. LUIKART **James L. Luikart**	Director
/s/ S. JAMES NELSON, JR. **S. James Nelson, Jr**	Director

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tracy W. Krohn, certify that:

1. I have reviewed this annual report on Form 10-K of W&T Offshore, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2007

/s/ TRACY W. KROHN

Tracy W. Krohn
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Gibbons, certify that:

1. I have reviewed this annual report on Form 10-K of W&T Offshore, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2007

/s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2006 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 9, 2007

/s/ TRACY W. KROHN

Tracy W. Krohn
Chief Executive Officer and President

Date: March 9, 2007

/s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President and Chief Financial Officer

Area of Focus & Corporate Information

Company Profie

Founded in 1983, W&T Offshore is an independent oil and natural gas company focused primarily in the Gulf of Mexico area, including the deep water and deep shelf regions. We have grown through acquisition, exploitation and exploration, and now hold working interests in approximately 200 fields in federal and state waters and have interests in leases covering approximately 2 million acres. Our proved reserves at December 31, 2006, were 735.2 Bcfe, of which 65 percent were proved developed reserves and 55 percent were natural gas reserves.

Corporate Office

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www.wtoffshore.com

Legal Counsel

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One Houston Center
1221 McKinney, Suite 4400
Houston, TX 77010
Telephone 713.652.5151
Fax 713.652.5152

Registrar and Transfer Agent

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

Computershare Investor Services, L.L.C.
2 North La Salle Street
Chicago, IL 60602
Telephone 312.588.4990
www-us.computershare.com

Independent Auditors

Ernst & Young LLP, Houston, TX

Independent Petroleum Consultants

Netherland, Sewell & Associates, Inc.
1601 Elm Street, Suite 4500, Dallas, TX 75201-4754

Common Stock Information

The common stock of W&T Offshore, Inc. is traded on the New York Stock Exchange under the symbol WTI. As of March 1, 2007, there were 157 registered holders of our common stock.

Annual Meeting

The Annual Meeting of Shareholders will be held at the Houston City Club, One City Club Drive, Houston, TX 77046 on May 15, 2007 at 10:00 a.m. Central Daylight Time.

Form 10-K and Quarterly Reports/Investor Contact

A copy of the W&T Offshore, Inc. Form 10-K for fiscal 2006, filed with the Securities and Exchange Commission, is available from the Company. Requests for investor-related information should be directed to Manuel Mondragon, Vice President of Finance, at the Company's corporate office or on the Internet at www.wtoffshore.com. E-mail: investorrelations@wtoffshore.com. The W&T Offshore, Inc. Form 10-K is also available on our website at www.wtoffshore.com. The most recent certifications by our President and Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to the Form 10-K. Tracy W. Krohn, our President and Chief Executive Officer, has also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

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