FORM 10−K

WTOFFSHORE INC − WTI

Filed: March 31, 2006 (period: December 31, 2005)

Annual report which provides a comprehensive overview of the company for the past year

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, 2005

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 **(State of incorporation)**	**72−1121985** **(IRS Employer Identification Number)**
Eight Greenway Plaza, Suite 1330 **Houston, Texas** **(Address of principal executive offices)**	**77046** **(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 $365,471,924 based on the closing sale price of $24.07 per share as reported by the New York Stock Exchange on June 30, 2005.

The number of shares of the registrant's common stock outstanding on March 15, 2006 was 65,979,875.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders to be held May 16, 2006 are incorporated by reference into Part III of this Form 10−K.

W&T OFFSHORE, INC.

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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 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 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 and exploration 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) and in acquiring rights to develop and exploit new prospects.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultant, our proved reserves at December 31, 2005 were 491.5 Bcfe. We calculate that our proved reserves had a PV−10 of approximately $2.4 billion and a standardized measure of after−tax discounted cash flows of approximately $1.6 billion as of December 31, 2005. Of those reserves, 65% were proved developed reserves and 44% were natural gas reserves.

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. During 2003, we acquired working interests in 13 offshore fields from ConocoPhillips. During 2004 and 2005, 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 historical profile and that we believe will add strategic and financial value to our company.

On January 23, 2006, we entered into an agreement with Kerr−McGee Oil & Gas Corporation ("Kerr−McGee") to acquire a subsidiary of Kerr−McGee by merger. We will own the surviving entity, which will be the successor to substantially all of Kerr−McGee's Gulf of Mexico conventional shelf properties. Base consideration for the transaction is approximately $1.3 billion in cash. The merger transaction is expected to close during the second or third quarter of 2006, subject to regulatory review and customary closing conditions and adjustments. The properties we will acquire by this merger include interests in approximately 100 fields on 249 offshore blocks (including 83 undeveloped blocks) and most of the properties are in water depths of 500 feet or less. For additional information about the pending transaction with Kerr−McGee, see Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee."*

For the year ended December 31, 2005, capital expenditures of $323.7 million included $174.6 million for development activities, $122.1 million for exploration, $26.3 million for acquisition and other leasehold activity and $0.7 million for other capital items. These expenditures do not include any amount of capitalized salaries or capitalized interest. Our capital expenditures for the year ended December 31, 2005 were financed by net cash flow provided by operating activities. We participated in the drilling of 22 exploratory wells and seven development wells of which 25 were on the conventional shelf and four were in the deepwater. Six of the development wells were successful. Of the 22 exploration wells, 17 were successful and two of the successful wells are in the deepwater. We operate 11 of the 17 successful exploratory wells, including the two successful exploratory wells in the deepwater. During the three−year period ended December 31, 2005, we drilled 66 exploratory wells, of which 48 were successful (which we define as completed or planned for completion).

During 2006, we expect to spend approximately $346 million on capital projects and approximately $54 million on major maintenance, expense workovers, seismic costs and plug and abandonments. These expenditures do not include estimated costs to repair damage to our facilities caused by Hurricanes Katrina and Rita in 2005, which we believe our insurance coverage will adequately cover. We anticipate drilling 25 exploratory wells and eight or more development wells in 2006. Our capital and major expenditure budget for 2006 does not include any incremental expenditures that may result from the transaction with Kerr−McGee. For additional information regarding potential changes in capital expenditures, see Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee."*

We actively participated in bidding for Gulf of Mexico leases on the outer continental shelf ("OCS") at lease sales conducted by the U.S. government through the Minerals Management Service ("MMS"). Of the 15 bids we submitted at the March 2005 OCS Lease Sale 194, the MMS awarded us leases covering eight OCS blocks located in the central Gulf of Mexico, two of which are in the deepwater. Of the four bids we submitted at the August 2005 OCS Lease Sale 196, the MMS awarded us one lease covering a block located in the deepwater of the western Gulf of Mexico. At the March 2006 OCS Lease Sale 198, we were the apparent high bidder on four of the seven bids submitted for blocks in the central Gulf of Mexico. Three of the blocks are in the deepwater and one block is on the conventional shelf. High bids are subject to MMS evaluation, which occurs within 90 days of the sale unless extended under extraordinary circumstances.

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 and, when available, royalty suspension incentives from the MMS should partially offset higher drilling costs.

We believe our historical 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.

In connection with the Kerr−McGee transaction, we may depend on our anticipated increased credit facility to fund the acquisition and related capital expenditures more heavily than we have in the past and for a longer period of time. In addition, we may issue debt or equity securities prior to or in conjunction with the closing of the transaction. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash flow and working capital" and "Recent Events—Transaction with Kerr−McGee.*"

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 various marketing companies. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2005 we sold over 10% of our production to each of the following companies: BP Amoco, Shell Trading, ConocoPhillips and Cinergy. 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 Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. 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 the FERC implements as to transportation and pipeline issues, 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 on 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 more light−handed 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 and drilling bonds 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 located on the OCS to meet stringent engineering and construction 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 plug 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.

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") imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of 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). MMS permit approvals will be conditioned on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases. MMS has issued Notices to Lessees and Operators ("NTL") 2003−G06 advising of requirements for posting of signs in prominent places on all vessels and structures.

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 we wish to develop, 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.

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.

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.

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, 2005, we employed 149 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., Eight Greenway Plaza, Suite 1330, 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 January 2006, we entered into commodity price hedges in connection with the anticipated financing related to the pending transaction with Kerr−McGee. While intended to reduce the effects of volatile oil and natural gas prices, hedging transactions, depending on the hedging instrument used, may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. 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 7 *“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee”* and Note 21 to our consolidated financial statements for additional information about the pending transaction with Kerr−McGee.

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

Our current credit facility limits our borrowings to $230.0 million based on our borrowing base. The borrowing base 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 those under our credit facility. 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. We plan to amend our current credit facility in connection with the Kerr−McGee transaction, as described in Item 7 *“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee.”*

Approximately 76% of our total proved reserves are undeveloped or non−producing and there can be no assurance that those reserves will ultimately be developed or produced.

Approximately 35% of our total proved reserves are undeveloped and approximately 41% are developed non−producing. Of the proved developed non−producing reserves, approximately 5% are non−producing due to damage caused by Hurricanes Katrina and Rita in 2005. While we have a development plan for exploiting and producing all of our proved reserves, there can be no assurance that those reserves will ultimately be developed or produced. We are not the operator with respect to 26% 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 3.6 years. Absent additional acquisitions or discoveries, our net well completions, as evaluated by our independent petroleum consultant, would be reduced from 158 to 85 in the next five years, even though we plan to drill additional development wells and to perform workovers. 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 Minerals Management Service, or 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 26% 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 25% of our proved undeveloped reserves and 27% 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;
- 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 2005 we were forced to defer company−wide production of approximately 5.7 Bcfe during the third quarter and approximately 11.7 Bcfe during the fourth quarter as a result of Hurricanes Cindy, Dennis, Katrina and Rita. During the three−year period ended December 31, 2005, we spent approximately $6.0 million to remediate hurricane damage that was not covered by insurance of which approximately $5.0 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 connection with the pending transaction with Kerr−McGee, we have received financing commitments from certain financial institutions for up to a $1.3 billion senior secured credit facility. See Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee."*

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 future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

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.

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 plug 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.

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

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 future acquisitions we make may involve numerous risks, including:

- potential disruption of our ongoing business;
- exposure to unknown liabilities;
- our lack of drilling history in the geographic areas in which the acquired business operates;
- the loss of key members of the acquired businesses following the acquisition;
- increased administration of new personnel; and
- additional costs due to entering new geographic locations and duplication of key talent.

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 acquisitions 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 Mcf, then the PV−10 value of our proved reserves as of December 31, 2005 would decrease from $2,416.5 million to $2,401.1 million. If oil prices decline by $1.00 per barrel, then the PV−10 value of our proved reserves as of December 31, 2005 would decrease from $2,416.5 million to $2,387.1 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. Should we increase 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.

The operator of a major offshore pipeline previously informed us that repairs mandated by the U.S. Department of Transportation require that the pipeline be shut−in for approximately six weeks; however, the estimated pipeline shut−in period has been revised to approximately two to four weeks. The repairs are expected to begin in June 2006. This will result in the deferral, but not the loss, of approximately 0.6 Bcfe (net) of production, which will impact the second and third quarters of 2006.

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. In 2003, we had to shut in a well when the third−party host platform was shut down by its owner. Currently, three of our wells, accounting for 46.9 Bcfe (or 9.5%) 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 plug 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. For instance, as a result of Hurricanes Katrina and Rita, we reported oil spills at different locations. None of these reports have resulted in fines or penalties nor have any adjudicatory actions occurred against us as a result. 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. During December 2005, our average net production from wells associated with this platform was approximately 10 MMcfe per day, representing less than six percent of our total production for the month. If we are required to curtail or cease production from this platform, it could adversely affect our cash flows, results of operations and asset value.

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 Chairman, Chief Executive Officer, President and Treasurer; W. Reid Lea, our Executive Vice President and Manager of Corporate Development; Jeffrey M. Durrant, our Senior Vice President of Exploration/Geoscience; Joseph P. Slattery, our Senior Vice President of Operations; or William W. Talafuse, our interim Chief Financial Officer and Chief Accounting Officer, 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 exploitation plans on a timely basis and within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration 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.

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. Accordingly, we will not be covered for financial losses incurred as a direct result of temporarily shutting in production during Hurricanes Cindy, Dennis, Katrina and Rita in 2005. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Our insurance is subject to annual renewal and we do not yet know how the insurance claims for the 2005 hurricanes will impact our future premiums. 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.

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 you 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 40,752,007 shares of our common stock, representing approximately 61.8% of our voting interests as of March 15, 2006. 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, 2005. At December 31, 2005, these fields accounted for approximately 58% of our PV−10 value, or $1.5 billion (before plug and abandonment cost), and had proved reserves totaling 291 Bcfe.

Field Name	Field Category	Operator	Percent Natural Gas of Net Reserves	2005 Average Daily Equivalent Sales Rate (MMcfe/d) Gross	Net
East Cameron 321	Shelf	W&T	30%	7.3	6.1
Green Canyon 19	Deepwater	ExxonMobil	14%	18.3	3.1
Green Canyon 646	Deepwater	W&T	17%	0.0	0.0
High Island 177	Shelf	W&T	75%	19.6	16.3
Main Pass 69	Shelf/Deep shelf	W&T	61%	3.8	3.2
Mississippi Canyon 718	Deepwater	Mariner	57%	0.0	0.0
Mobile 823	Shelf	ExxonMobil	87%	73.9	7.7
Ship Shoal 349	Shelf	W&T	18%	11.0	5.4
South Timbalier 228	Shelf	W&T	17%	5.3	4.4
West Delta 30	Shelf	W&T and Anglo−Suisse (1)	3%	4.8	4.0

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

Proved Reserves

Of our 491.5 Bcfe of proved reserves at December 31, 2005, 65% were proved developed and 44% were natural gas. 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, 2005 are summarized below.

	As of December 31, 2005				
Classification of Reserves (1)	Oil (MMBbls)	Gas (Bcf)	Total (Bcfe)	% of Total Proved	PV−10 (3) (In millions)
Proved developed producing	8.5	69.0	120.1	24%	$ 737.0
Proved developed non−producing (2)	16.3	101.0	198.5	41%	1,055.4
Total proved developed	24.8	170.0	318.6	65%	1,792.4
Proved undeveloped	21.1	45.9	172.9	35%	624.1
Total proved	45.9	215.9	491.5	100%	$ 2,416.5

(1) Totals may not add due to rounding.
(2) Includes 23.5 Bcfe of reserves with a PV−10 of $134.3 million that were shut−in at December 31, 2005 because of Hurricanes Katrina and Rita in 2005.
(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, 2005. 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	648,663	323,461	122,403	81,118	771,066	404,579
Deepwater	78,726	46,840	82,032	77,232	160,758	124,072
	727,389	370,301	204,435	158,350	931,824	528,651

Approximately 80% 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 approximately the same amount of our acreage as is held−by−production.

Production

During 2005, our net production averaged approximately 195 MMcfe per day with approximately 48 MMcfe per day temporarily shut in as a result of Hurricanes Cindy, Dennis, Katrina and Rita. See Item 1A "*Risk Factors—Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses*" for a further discussion of the effect of these events on our business.

Production History

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

	Year Ended December 31,		
	2005	2004	2003
Net sales:			
Natural gas (Bcf)	46.5	53.3	52.8
Oil (MMBbls)	4.1	4.8	4.4
Total natural gas and oil (Bcfe)	71.1	82.4	79.0

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, 2005 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	82	64.6	72	52.2	154	116.8
Non−operated	101	20.8	112	26.1	213	46.9
	183	85.4	184	78.3	367	163.7

(1) Includes two gross (0.3 net) oil wells and eight gross (2.6 net) gas wells with multiple completions.

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

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	20	12.2	11	7.1	31	19.3
Non−operated	48	9.0	48	10.3	96	19.3
	68	21.2	59	17.4	127	38.6

Drilling Activity

The following lists our successful exploratory wells that were drilled in 2005 and their estimated cost as of December 31, 2005 (dollars in millions).

Block	Working Interest	Estimated Cost Gross	Estimated Cost Net	Water Depth (feet)	Date Objective Drilled/Tested
Conventional Shelf:					
Eugene Island 218 D−5ST	100%	$ 6.1	$ 6.1	105	2nd Quarter
Eugene Island 218 I−3	100%	1.6	1.6	115	1st Quarter
Eugene Island 219 E−8ST	100%	2.8	2.8	115	2nd Quarter
Eugene Island 349 B−9ST	29%	7.2	2.1	298	4th Quarter
High Island A443 A−2ST	84%	3.3	2.8	180	4th Quarter
High Island A443 A−5ST	92%	1.8	1.7	180	3rd Quarter
High Island A568 A−19	33%	12.4	4.1	271	2nd Quarter
Main Pass 185 #1	33%	15.8	5.2	155	3rd Quarter
Mustang Island 889 F−1	50%	13.6	6.8	30	4th Quarter
Ship Shoal 130 J−1	100%	10.4	10.4	47	4th Quarter
Ship Shoal 149 G−3ST	100%	1.1	1.1	55	1st Quarter
Ship Shoal 149 G−8ST	100%	1.5	1.5	55	1st Quarter
Ship Shoal 149 G−9	100%	1.6	1.6	55	1st Quarter
West Cameron 328 #2	25%	4.0	1.0	70	2nd Quarter
West Cameron 638 A−32	27%	6.3	1.7	262	1st Quarter
Deepwater:					
Ewing Bank 949 #2ST	100%	10.6	10.6	865	2nd Quarter
Ewing Bank 989 #1	100%	24.5	24.5	523	3rd Quarter
		$124.6	$85.6		

Development and Exploration Drilling

The following sets forth the results of our total drilling activities for the last three years.

	Year Ended December 31,		
	2005	2004	2003
Gross Wells:			
Productive	23	28	16
Non−productive	6	11	3
	29	39	19
Net Wells:			
Productive	15.4	18.0	6.6
Non−productive	2.5	7.7	0.9
	17.9	25.7	7.5

Exploration Drilling

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

	Year Ended December 31,		
	2005	2004	2003
Gross Wells:			
Productive	17	21	10
Non−productive	5	11	2
	22	32	12
Net Wells:			
Productive	12.7	13.7	4.2
Non−productive	2.4	7.7	0.7
	15.1	21.4	4.9

Current Drilling Activity

We were in the process of drilling three gross (3.0 net) exploration wells as of March 15, 2006.

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.

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Executive Officers of the Registrant

The following lists our executive officers:

Name	Age	Position
Tracy W. Krohn	51	Founder, Chairman, Chief Executive Officer, President, Treasurer and Director
Jerome F. Freel	93	Founder, Secretary, Director and Chairman Emeritus
W. Reid Lea	47	Executive Vice President and Manager of Corporate Development
Jeffrey M. Durrant	51	Senior Vice President of Exploration/Geoscience
Joseph P. Slattery	53	Senior Vice President of Operations
William W. Talafuse	59	Senior Vice President, interim Chief Financial Officer and Chief Accounting Officer

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 since 1997. Mr. Krohn's mother is married to Jerome F. Freel.

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

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.

William W. Talafuse has served as Senior Vice President and Chief Accounting Officer of the Company since September 28, 2005. Mr. Talafuse has served as interim Chief Financial Officer since March 28, 2006. Mr. Talafuse joined the Company in July 2004 as Vice President of Accounting and Chief Accounting Officer. Prior to joining our Company, Mr. Talafuse was with TransTexas Gas Corporation, an independent exploration and production company, and its affiliates for 16 years. Mr. Talafuse served as Controller of TransTexas Gas Corporation from October 1998 until he joined the Company.

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 the range of high and low sales prices for the period January 28, 2005 through March 31, 2005 and for each quarterly period from April 1, 2005 through December 31, 2005.

Period Ended	High	Low
March 31, 2005	$ 22.25	$ 18.05
Quarter Ended	**High**	**Low**
June 30, 2005	$ 24.43	$ 19.30
September 30, 2005	34.44	24.03
December 31, 2005	32.43	24.54

As of March 15, 2006, there were 107 registered holders of our common stock.

Dividends

Under the second amended and restated credit facility that we entered into on March 15, 2005, we are allowed to pay annual dividends up to $30 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 facility.

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).

Quarter Ended	Aggregate Dividends on Common Stock	Dividend per Share of Common Stock	Aggregate Dividends on Series A Preferred Stock	Dividend per Share of Series A Preferred Stock
June 30, 2004	$ 1,183	$ 0.02	$ 300	$ 0.15
September 30, 2004	1,183	0.02	300	0.15
December 31, 2004	1,184	0.02	300	0.15
March 31, 2005	1,319	0.02	—	—
June 30, 2005	1,319	0.02	—	—
September 30, 2005	1,320	0.02	—	—
December 31, 2005	1,980	0.03	—	—

On March 13, 2006, the Company's board of directors declared a cash dividend of $0.03 per share of common stock, payable on May 1, 2006 to shareholders of record on April 14, 2006. 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.

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,				
	2005	2004	2003 (1)	2002 (1)	2001
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income Information:					
Revenues:					
Oil and gas	$ 584,564	$508,195	$421,435	$189,892	$169,054
Other	572	520	1,152	1,443	534
Total revenues	585,136	508,715	422,587	191,335	169,588
Operating costs and expenses:					
Lease operating	71,758	73,475	65,947	26,454	22,099
Gathering, transportation and production taxes	12,702	14,099	10,213	3,672	5,048
Depreciation, depletion and amortization	174,771	155,640	136,249	89,941	65,293
Asset retirement obligation accretion (2)	9,062	9,168	7,443	—	—
General and administrative (3)(4)(5)	28,418	25,001	22,912	10,060	9,677
Total operating costs and expenses	296,711	277,383	242,764	130,127	102,117
Impairment of subsidiary assets (6)	—	—	—	3,750	—
Income from operations	288,425	231,332	179,823	57,458	67,471
Interest income (expense), net	1,601	(1,842)	(2,229)	(3,001)	(3,902)
Income before income taxes	290,026	229,490	177,594	54,457	63,569
Income taxes (7)	101,003	80,008	61,156	52,408	—
Cumulative effect of change in accounting principle (net of taxes of $77) (2)	—	—	144	—	—
Net income	189,023	149,482	116,582	2,049	63,569
Less preferred stock dividends	—	900	5,876	—	—
Net income applicable to common shares	$ 189,023	$148,582	$110,706	$ 2,049	$ 63,569
Net income per common share (8):					
Basic earnings per share	$ 2.91	$ 2.82	$ 2.14	$ —	$ —
Diluted earnings per share	2.87	2.27	1.79	—	—
Common stock dividends	5,938	3,550	35,124	—	—
Cash dividends per common share	0.09	0.07	0.67	—	—
Subchapter S corporation tax distributions	—	—	—	13,883	14,001
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 444,043	$377,275	$263,155	$147,809	$123,884
Capital expenditures	323,743	284,847	203,400	116,759	126,399
Other Financial Information:					
EBITDA (9)	$ 472,258	$396,140	$323,659	$147,399	$132,764

	December 31,				
	2005	2004	2003	2002	2001
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Total assets	$1,064,520	$760,784	$546,729	$341,194	$282,483
Long−term debt	40,000	35,000	67,000	99,600	82,400
Shareholders' equity	543,383	359,878	214,455	133,330	164,182

(1) 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) Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. The cumulative effect of the change in accounting principle is $221 thousand ($144 thousand net of income taxes). See Note 3 to our consolidated financial statements.
(3) The amounts for 2005 and 2004 include approximately $0.9 million and $1.5 million, respectively, of expenses associated with our initial public offering, which was completed in January 2005. Also 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.
(4) 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.
(5) G&A expenses related to our long−term incentive compensation plans were $2.3 million, $0.6 million and $9.3 million in 2005, 2004 and 2003, respectively.
(6) This impairment is related to the sale of a subsidiary to two of our shareholders. See Notes 5 and 16 to our consolidated financial statements.
(7) 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.
(8) Net income per share information has not been presented for 2001 and 2002 because we were an S corporation during the majority of that period of time. The results for those years would not be comparable to the presentation for 2005, 2004 and 2003.
(9) We define EBITDA as net income plus income tax expense, net interest expense, depreciation, depletion, amortization and accretion. Although not prescribed by generally accepted accounting principles (“GAAP”), we believe the presentation of EBITDA is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies that have different financing, capital or tax structures. 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, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use. The following presents a reconciliation of our consolidated net income to consolidated EBITDA.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(Dollars in thousands)				
Net income	$ 189,023	$ 149,482	$ 116,582	$ 2,049	$ 63,569
Income taxes	101,003	80,008	61,156	52,408	—
Net interest (income) expense	(1,601)	1,842	2,229	3,001	3,902
Depreciation, depletion, amortization and accretion	183,833	164,808	143,692	89,941	65,293
EBITDA	$ 472,258	$ 396,140	$ 323,659	$ 147,399	$ 132,764

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, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Item 1 *"Business"* and Item 7 *"Properties."* The selected historical operating data set forth below should be read in conjunction with "*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,				
	2005	**2004**	**2003**	**2002**	**2001**
Reserve Data:					
Estimated net proved reserves (1):					
Natural gas (Bcf)	215.9	227.6	231.1	219.0	154.7
Oil (MMBbls)	45.9	40.0	35.6	23.1	15.2
Total natural gas and oil (Bcfe)	491.5	467.5	444.7	357.5	245.7
Proved developed producing (Bcfe)	120.1	145.8	135.5	108.1	69.2
Proved developed non−producing (Bcfe) (2)	198.5	144.4	160.1	121.1	103.7
Total proved developed (Bcfe)	318.6	290.1	295.6	229.2	173.0
Proved undeveloped (Bcfe)	172.9	177.3	149.1	128.3	72.7
Proved developed reserves as a percentage of proved reserves	64.8%	62.1%	66.5%	64.1%	70.4%
Reserve additions (Bcfe):					
Acquisitions	14.2	19.2	124.1	128.3	2.1
Extensions, discoveries and other additions	60.6	65.2	48.6	24.2	93.0
Revisions	20.3	20.9	(6.5)	15.0	(12.9)
Total net reserve additions	95.1	105.3	166.2	167.5	82.2

	Year Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Operating Data:					
Net sales (3):					
Natural gas (MMcf)	46,548	53,348	52,807	39,368	28,412
Oil (MBbls)	4,085	4,847	4,373	2,465	2,314
Total natural gas and oil (MMcfe) (1)	71,060	82,432	79,045	54,158	42,296
Average daily equivalent sales (MMcfe/d) (3)	194.7	225.2	216.6	148.5	115.9
Average realized sales prices (3):					
Natural gas ($/Mcf)	$ 8.27	$ 6.18	$ 5.60	$ 3.34	$ 4.11
Oil ($/Bbl)	48.85	36.77	28.74	23.57	22.66
Natural gas equivalent ($/Mcfe)	8.23	6.16	5.33	3.50	4.00
Average per Mcfe data ($/Mcfe):					
Lease operating expenses	$ 1.01	$ 0.89	$ 0.83	$ 0.49	$ 0.52
Gathering, transportation costs and production taxes	0.18	0.17	0.13	0.07	0.12
Depreciation, depletion, amortization and accretion	2.59	2.00	1.82	1.66	1.54
General and administrative expenses	0.40	0.30	0.29	0.19	0.23
Total number of wells drilled (gross)	29	39	19	11	25
Total number of productive wells drilled (gross)	23	28	16	9	24

(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) Includes 23.5 Bcfe of reserves that were shut−in at December 31, 2005 because of Hurricanes Katrina and Rita in 2005.
(3) We did not engage in any hedging transactions during the 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 and exploration activities, primarily in the Gulf of Mexico. We own working interests in approximately 105 producing fields in federal and state waters and we operated wells accounting for approximately 68% of our average daily production in the month of December 2005. We have interests in leases covering approximately 932,000 acres spanning across the outer continental shelf off the coast of Louisiana, Texas, Mississippi and Alabama. We own interests in approximately 261 offshore structures, of which 106 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 solely for the sake of recording 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. During 2005 and 2004, we did not complete any significant acquisitions. During 2003, we acquired working interests in 13 offshore fields from ConocoPhillips.

On January 23, 2006, we entered into an agreement with Kerr−McGee Oil & Gas Corporation ("Kerr−McGee") to acquire a subsidiary of Kerr McGee by merger. The properties we will acquire by this merger include interests in approximately 100 fields on 249 offshore blocks (including 83 undeveloped blocks) and most of the properties are in water depths of 500 feet or less. See *"Recent Events—Transaction with Kerr−McGee."*

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 all 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 2005, we sold an average of approximately 128 MMcf of natural gas per day and approximately 11,000 Bbls of oil per day. Our revenues in 2005 benefited from a general rise in oil and natural gas prices over the year. During the years ended December 31, 2005, 2004 and 2003, we did not engage in any commodity or financial hedging transactions. However, as explained in Note 21 to our consolidated financial statements, in January 2006 we entered into commodity price hedges in connection with the anticipated financing related to the pending transaction with Kerr−McGee.

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 may 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 plug 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 $152.3 million discounted at 8% at December 31, 2005, because we operate under an exemption from certain bonding requirements under MMS rules.

Effects on Production from Storms in the Gulf of Mexico

In 2005, four storms (Hurricanes Cindy, Dennis, Katrina and Rita) caused production delays and deferrals. As a result of these storms, we were forced to defer company−wide production of approximately 5.7 Bcfe during the third quarter of 2005 and approximately 11.7 Bcfe during the fourth quarter of 2005. The majority of these production delays and deferrals were attributable to Hurricanes Katrina and Rita. As of March 15, 2006, our production was approximately 190 MMcfe per day (net) and production of approximately 31 MMcfe per day (net) remained shut−in. Also as of March 15, 2006, we have completed inspections on 37 of 86 platforms that were required to be inspected in accordance with MMS regulations as a result of Hurricanes Katrina and Rita. In total, five gross operated platforms sustained significant physical damage as a result of Hurricanes Katrina and Rita and our inspections have not revealed any additional significant damage to our structures. We expect to return to pre−Katrina production levels in the third quarter of 2006.

Results of Operations

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 14 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. 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. 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 14 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 and dividend income. Interest and dividend 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.

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.

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%.

Net income. Net income for the year ended December 31, 2005 increased $39.5 million to $189.0 million. The primary reasons for this increase were as follows:

- higher oil prices in 2005 of $48.85 per barrel, as compared to $36.77 per barrel in the same period in 2004;
- higher natural gas prices in 2005 of $8.27 per Mcf, as compared to $6.18 per Mcf in the same period in 2004;
- lower lease operating expenses, gathering and transportation costs and interest expense in 2005, compared to 2004; and
- higher interest and dividend income in 2005, compared to 2004.

Offsetting these favorable factors were lower volumes of crude oil and natural gas sold in 2005 primarily due to shut−in production caused by severe weather in the Gulf Coast area and increases in DD&A, G&A and income taxes, compared to 2004.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and natural gas revenues. Oil and natural gas revenues increased $86.8 million to $508.2 million for the year ended December 31, 2004. Natural gas revenues increased $34.2 million and oil revenues increased $52.6 million. The natural gas revenue increase was caused by a 0.5 Bcf sales volume increase and a 10% increase in the average realized natural gas price from $5.60 per Mcf for the year ended December 31, 2003 to $6.18 per Mcf for the same period in 2004. The oil revenue increase was caused by a sales volume increase of 474 MBbls for the year ended December 31, 2004 and a 28% increase in the average realized price, from $28.74 per barrel in 2003 to $36.77 per barrel in 2004. The volume increase for oil and natural gas was primarily attributable to our acquisition transaction with ConocoPhillips in December 2003. Sales volumes for all products were negatively impacted for the year ended December 31, 2004 by the curtailment of production due to Hurricane Ivan, which reduced average daily equivalent sales for the three months ended December 31, 2004 by approximately 2%.

Lease operating expenses. Our lease operating expenses increased from $65.9 million in 2003 to $73.5 million in the same period of 2004. The increase is attributable in part to properties we acquired during December 2003. On a per Mcfe basis, lease operating expenses increased 7%, from $0.83 per Mcfe in 2003 to $0.89 per Mcfe in 2004 primarily due to higher operating costs associated with existing properties. Approximately $1.6 million of the increase relates 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.

Gathering and transportation costs and production taxes. Gathering and transportation costs increased from $9.9 million in 2003 to $13.7 million in 2004, due primarily to an increase in the volume of our production during 2004 and increased transportation costs. Production taxes did not materially change during the year ended December 31, 2004 as compared to 2003. 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 $143.7 million in 2003 to $164.8 million in 2004. On a per Mcfe basis, DD&A was $2.00 for the year ended December 31, 2004, compared to $1.82 for the same period in 2003. The increase in DD&A was a result of higher production volumes, combined with a higher depletion rate, an increase in our total depletable costs due to our drilling activities and the lack of additions to our oil and natural gas reserves in quantities sufficient to offset reserves added through acquisitions in the prior year.

General and administrative expenses. General and administrative expenses ("G&A") increased from $22.9 million for the year ended December 31, 2003 to $25.0 million in the same period of 2004. Approximately $1.5 million of the increase relates to expenses associated with our initial public offering, which was completed in January 2005. During 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 $5.2 million of expenses related to this bonus are included in G&A for the year ended December 31, 2004. In 2003, the Company granted incentive compensation awards of $9.3 million to certain key employees (other than our Chief Executive Officer and our Corporate Secretary).

Interest expense. Interest expense decreased from $2.5 million for the year ended December 31, 2003 to $2.1 million in the same period of 2004 due primarily to lower average borrowings during 2004 offset by increased fees related to the unused portion of our credit facility.

Income tax expense. Income tax expense increased from $61.2 million in 2003 to $80.0 million in 2004 primarily due to increased taxable income. Our effective tax rate for the years ended December 31, 2004 and 2003 was 35% and 34%, respectively.

Net income. Net income for the year ended December 31, 2004 increased $32.9 million to $149.5 million. The primary reasons for this increase were as follows:

- higher volumes of crude oil and natural gas sold in 2004, as compared to the same period in 2003;
- higher oil prices in 2004 of $36.77 per barrel, as compared to $28.74 per barrel in the same period in 2003; and
- higher natural gas prices in 2004 of $6.18 per Mcf, as compared to $5.60 per Mcf in the same period in 2003.

Offsetting these favorable factors were increases in lease operating expenses, transportation costs, DD&A, G&A and income taxes.

Liquidity and Capital Resources

Cash flow and working capital. Net cash flow provided by operating activities for the year ended December 31, 2005 increased to $444.0 million, compared to $377.3 million for the comparable period in 2004 primarily due to the increase in net income. Net cash flow used in investing activities totaled $321.5 million and $279.9 million during 2005 and 2004, respectively, which primarily represents our investment in oil and gas properties. In 2005, net cash flow provided by financing activities was $0.2 million and in 2004, net cash flow used in financing activities was $36.5 million. In total, cash and cash equivalents increased from $65.0 million as of December 31, 2004 to $187.7 million as of December 31, 2005. In recent years, we have been able to fund our investing activities and repay long−term debt borrowings with our operating cash flow.

Increases in our operating cash flows from 2003 through 2005 are attributable to several factors. In 2004, operating cash flows were favorably impacted by higher sales volumes and an increase in the average prices realized on sales of oil and natural gas, compared to 2003. 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 third quarter of 2006 of our estimated federal income tax payments originally due on September 15 and December 15, 2005 (see Notes 9 and 17 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. We anticipate our 2006 production volumes will be negatively impacted by deferrals related to damage caused by Hurricanes Katrina and Rita; however, continued high commodity prices could reduce the effects of this deferred production on cash flows from operations.

We had working capital of $52.1 million at December 31, 2005 and a working capital deficit of $10.5 million at December 31, 2004. 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. We believe that our working capital balance should be viewed in conjunction with our cash provided by operations and the availability of borrowings under our credit facility when measuring liquidity.

We maintain insurance against many of the risks associated with exploration and production activities in the Gulf of Mexico. We do not carry business interruption insurance. We have notified our insurance underwriters of our potential property damage and we will file claims for damages caused by the hurricanes in 2005. We have been assigned and have been working with an adjuster and are evaluating and documenting the hurricane damage. We currently estimate the total cost to repair damages to our facilities caused by Hurricanes Katrina and Rita will range from $60 million to $75 million. As of December 31, 2005 we have incurred $11.6 million of costs to remediate damage caused by Hurricanes Katrina and Rita. Our insurance policy covering physical damage has a cumulative annual deductible of $5 million that must be satisfied before we are indemnified for losses. Of this amount, $1.6 million is included in lease operating expenses and $3.4 million is included in oil and gas properties. The costs we have incurred in excess of our deductible, or $6.6 million, is included in joint interest and other receivables. We believe that our insurance coverage is adequate to cover losses associated with Hurricanes Katrina and Rita and are not aware of any reason why coverage may be limited or denied; however, it is possible that the insurance companies may contest our claims. We expect that our available cash and cash equivalents, cash flow from operations and the availability of our credit facility will be sufficient to meet any uninsured expenditures.

We intend to fund our future exploration and exploitation expenditures and the pending transaction with Kerr−McGee through net cash flow from operating activities, borrowings from credit facilities, cash on hand and, if necessary, additional debt or equity financings. Our future net cash flow provided by operating activities will depend on our ability to restore, maintain and increase production through our operations, drilling and acquisition programs, as well as the prices of oil and gas. In connection with the Kerr−McGee transaction, we plan to increase our existing credit facility. However, current and planned credit commitments may not be sufficient to cover the full cost of the Kerr−McGee transaction at closing due to volatile oil and natural gas prices, delayed, deferred or lost production resulting from the hurricanes in 2005 and the amount of available cash. We may be required to increase the amount of our commodity hedges to increase or maintain the credit commitments. We may elect to defer some of our planned capital or other expenditures in the interim in order to increase cash on hand. We may issue debt or equity securities prior to or in conjunction with the closing, either to provide the additional capital necessary to effect the closing or to provide us additional financial flexibility through increased cash on hand or lower debt. See “*Recent Events—Transaction with Kerr−McGee*.”

Credit facility. On March 15, 2005, we entered into a $300 million secured revolving credit facility with an initial borrowing base of $230 million, which is subject to redetermination on March 1 and September 1 of each year. Security for the credit facility is 80% of the value of our oil and gas properties, as determined by our lenders. As of December 31, 2005, we had $40 million in long−term debt outstanding under the credit facility and had $0.3 million of letters of credit outstanding, with $189.7 million of undrawn capacity. The indebtedness outstanding at December 31, 2005 was repaid in January 2006. As of March 15, 2006, we had no long−term debt outstanding under the credit facility and had $0.3 million of letters of credit outstanding, with $229.7 million of undrawn capacity. If the borrowing base of the credit facility is determined to be lower than the then outstanding amount of loans and letters of credit, we must pay the difference in three monthly installments or provide additional collateral satisfactory to the lenders. The maturity date of the credit facility has been extended to March 15, 2009, when the entire amount outstanding, if any, will be due. 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 0.625%

depending upon the ratio of the amounts outstanding to the borrowing base 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 1.875%, depending upon the ratio of the amounts outstanding to the borrowing base.

The current credit facility has covenants that restrict the payment of cash dividends to $30 million per year, borrowings, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and entering into certain other transactions without the prior consent of the lenders and requires us to maintain a ratio of current assets (which is a term defined in the credit facility agreement to include the undrawn capacity of our borrowing base) to current liabilities of one−to−one and a ratio of EBITDA to interest expense of five−to−one, as well as a minimum tangible net worth, which minimum varies with our cumulative net income and the amount of proceeds we receive from issuing stock. The credit agreement requires us to maintain a lien in favor of the lenders on properties representing at least 80% of the total value of our oil and gas properties. In addition, we have granted a security interest in other collateral including 100% of our ownership interests in our subsidiaries. Our operating subsidiaries have also guaranteed our obligations under the credit agreement and granted liens on approximately 80% of the value of their property. Restrictions in our credit facility substantially prohibit us from borrowing any amounts except those drawn on our credit facility and from borrowing any amounts on the credit facility during an event of default. Prior consent of the lenders is required to sell assets for consideration in excess of $30 million. From time to time, we have requested and received permission from our lenders to sell assets. We were in compliance with our covenants under the credit agreement on December 31, 2005. In connection with the Kerr−McGee transaction, we plan to increase our existing credit facility. The terms and conditions of our increased credit facility are to be negotiated in connection with the Kerr−McGee transaction. See *"Recent Events—Transaction with Kerr−McGee."*

During the year ended December 31, 2005, we borrowed and repaid $42.6 million and $37.6 million, respectively, under our credit agreement. During the years ended December 31, 2004 and 2003, we borrowed $212.1 million and $253.2 million, respectively, under our credit agreement to finance investments and acquisitions, but consistent with our financial approach, we repaid these borrowings as soon as possible. Payments under our credit agreement totaled $244.1 million in 2004 and $285.8 million in 2003.

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, 2005, capital expenditures of $323.7 million included $174.6 million for development activities, $122.1 million for exploration, $26.3 million for acquisition and other leasehold activity and $0.7 million for other capital items. These expenditures do not include any amount of capitalized salaries or capitalized interest but do include dry hole costs of $30.8 million. Our capital expenditures for the year ended December 31, 2005 were financed by net cash flow provided by operating activities.

During 2005, we participated in the drilling of 22 exploratory wells and seven development wells of which 25 were on the conventional shelf and four were in the deepwater. Six of the development wells were successful. Of the 22 exploration wells, 17 were successful and two of the successful wells are in the deepwater. We operate 11 of the 17 successful exploratory wells, including the two successful exploratory wells in the deepwater. Of the drilling, completion and facilities expenditures budgeted for 2005, we spent $92.0 million in the deepwater, $21.5 million on the deep shelf and $183.2 million on the conventional shelf and other projects. Additionally, we spent $14.6 million on expensed workovers and major maintenance projects and $17.9 million for plug and abandonment expenses.

During 2004, we invested $282.5 million in oil and gas properties, including drilling 21.4 net exploration wells and 4.3 net development wells. During 2003, our oil and gas investments totaled $201.3 million, including a significant acquisition of a subsidiary of ConocoPhillips, numerous acquisitions of other interests and drilling 4.8 net exploration wells and 2.7 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 2006, we expect to spend approximately $346 million on capital projects and approximately $54 million on major maintenance, expense workovers, seismic costs and plug and abandonments. These expenditures do not include estimated costs to repair damage to our facilities caused by Hurricanes Katrina and Rita in 2005, which we believe our insurance coverage will adequately cover. We anticipate drilling 25 exploratory wells and eight or more development wells in 2006. Our capital and major expenditure budget for 2006 does not include any incremental expenditures that may result from the transaction with Kerr−McGee. Refer to *"Recent Events—Transaction with Kerr−McGee."*

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.

Contractual obligations. The following summarizes our obligations and commitments as of December 31, 2005 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. All amounts listed in the table below are categorized as liabilities on our balance sheet with the exception of lease payments for operating leases and outstanding letters of credit issued for performance obligations. At December 31, 2005, we did not have any capital leases or long−term contracts for drilling rigs or equipment.

	Payments Due by Period at December 31, 2005				
	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 (1)	$ 40.0	$ —	$ —	$ 40.0	$ —
Operating leases	7.0	1.1	3.3	1.9	0.7
Letters of credit	0.3	0.3	—	—	—
Asset retirement obligations	152.3	39.7	16.4	14.2	82.0
Other liabilities	2.4	—	2.4	—	—
	$202.0	$ 41.1	$ 22.1	$ 56.1	$ 82.7

(1) As of December 31, 2005, we had $40.0 million long−term debt outstanding under our credit facility. In January 2006, this amount was repaid in full.

Recent Events

Transaction with Kerr−McGee. On January 23, 2006, we entered into an agreement with Kerr−McGee Oil & Gas Corporation ("Kerr−McGee") to acquire a subsidiary of Kerr−McGee by merger. We will own the surviving entity, which will be the successor to substantially all of Kerr−McGee's Gulf of Mexico conventional shelf properties. The agreement is effective as of October 1, 2005 and we expect the transaction to close in the second or third quarter of 2006, subject to customary closing conditions and regulatory approvals. The base merger consideration is approximately $1.3 billion and is subject to adjustments based on production proceeds, expenses, environmental defects, title defects and other factors.

The properties to be acquired by the pending merger with the Kerr−McGee subsidiary include interests in approximately 100 fields on 249 offshore blocks (including 83 undeveloped blocks). Most of the properties are on the conventional shelf in water depths of 500 feet or less. We currently estimate total proved reserves of these properties to be approximately 345 Bcfe as of October 1, 2005 based on further analysis since our initial evaluation and based on October 2005 commodity prices. We have retained Netherland, Sewell & Associates, Inc., our independent petroleum consultant, to prepare an estimate of the total proved reserves of these properties. The production of the Kerr−McGee properties for the fourth quarter of 2005 was approximately 11 Bcfe and the current production is approximately 140 MMcfe per day. The production build up from the Kerr−McGee properties is not occurring as quickly as we had originally anticipated in October 2005, but we believe this is consistent with the delays that are occurring across the industry due to infrastructure damage caused by the hurricanes in 2005.

In connection with the merger, we have received financing commitments for up to a $1.3 billion senior secured credit facility. The terms and conditions of the increased credit facility are to be negotiated in connection with the Kerr−McGee transaction, and these commitments will be subject to customary conditions that must be met prior to funding. We expect to finance this transaction through a combination of cash on hand and debt under this facility. Based on production and other expected adjustments to the base merger consideration, as well as the use of cash on hand, we do not currently anticipate using the entire amount available under this credit facility to finance the transaction. In anticipation of the financing, we have also entered into commodity price hedges. These hedges are intended to reduce the effects of volatile oil and gas prices. These hedges may also have the effect of limiting our potential gains and exposing us to potential financial losses. The financing is expected to increase our financial leverage on the whole and may change our risk profile, but we believe this effect will be substantially reduced within the first 12 to 18 months due to the expected scheduled amortization payments. In addition, if the increased credit facility does not close by May 11, 2006, our borrowing capacity may be reduced by taking into account the expected amortization payment from the date of the expected closing date to the actual closing date. For additional information on events that could affect our cash on hand and available borrowing capacity under the increased credit facility for the funding of the Kerr−McGee transaction, see "*Liquidity and Capital Resources—Cash flow and working capital*."

If this transaction closes as anticipated, we plan to increase our capital expenditure budget by approximately $50 million for development purposes in 2006. We expect to fund such increase primarily out of the production from such properties and available borrowing capacity under the increased credit facility. This acquisition may increase our need for external capital to develop such properties if our production is lower than expected or as a result of decreases in oil and gas prices. The acquisition may also require us to alter or increase our capitalization through the issuance of debt or equity securities, the sale of production payments or other means.

2005 Bonus Award. In March 2006, our board of directors approved payment of a general bonus and an extraordinary bonus for 2005 under our incentive compensation plan. Although not all of the performance measures for the extraordinary bonus were met, our board determined that substantially all of the performance measures would have been met were it not for the effects of Hurricanes Katrina and Rita. The total cash portion of the 2005 general bonus is $2.8 million, of which $2.2 million has been expensed in 2005. The total cash portion of the extraordinary bonus is $1.4 million and will be expensed in the first quarter of 2006. The total restricted stock portion of the general bonus is $4.0 million and the total restricted stock portion of the extraordinary bonus is $2.0 million. The restricted stock will vest in three equal increments on December 31 of 2006, 2007 and 2008 and the associated compensation expense will be recognized over the vesting period. A total of 160,377 restricted shares were granted in connection with the 2005 bonuses.

Inflation and Seasonality

Inflation. While we have benefited from a general rise in the price of both oil and natural gas, the prices for drilling rigs, drilling services, offshore transportation services and steel have impacted our lease operating expenses and our capital spending in 2005 and we expect the prices of such goods and services will increase in 2006. 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. For example, the daily rate charged for a drilling rig capable of drilling in 600 feet of water has increased substantially from the daily rate charged in 2003 and we expect daily rates to continue to rise in 2006.

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.

Off−Balance Sheet Arrangements

We have outstanding letters of credit in the face amount of $0.3 million that we have posted to secure a portion of our areawide operators' bonding obligations required by the MMS.

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. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and if the collection of the revenue is probable. The Company uses the sales method of accounting for its oil and gas revenues; therefore, no accruals are made for imbalances between production and allocated sales. Historically, these differences have not been material. Under this method of accounting, revenue is recorded based upon the Company's physical deliveries to its customers, which can be different from the Company's net working interest in field production. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under−produced party to recoup its entitled share through production. As of December 31, 2005, 2004 and 2003, deliveries of natural gas in excess of the Company's working interest and under−deliveries 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, virtually all acquisition, exploration, development and estimated abandonment cost incurred for the purpose of acquiring or finding oil and natural gas are capitalized. Under the full−cost method, however, we are permitted to charge to expense certain employee costs and G&A related to these activities and, in particular, most of our geological and geophysical cost. Total capitalized geological and geophysical costs on our balance sheet were approximately $28 million and $22 million at December 31, 2005 and 2004, respectively. We expensed approximately $4.3 million and $2.5 million in geological and geophysical administrative cost during 2005 and 2004, respectively. 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. We amortize our investment in oil and natural gas properties through DD&A, using the units of production method. We have not excluded any expenditures related to our oil and gas properties from amortization and have not capitalized any interest during the years ended December 31, 2005, 2004 or 2003.

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 and in the resulting computation of DD&A. Under the full−cost method, which we follow, some 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, 2005 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 plug and abandonment expenses in our calculation of PV−10 reserve estimates. Approximately 76% of our reserves at December 31, 2005 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 38% of these proved undeveloped reserves have been booked within one year of the most recent reserve report and approximately 58% of these proved undeveloped reserves have been booked within two years of December 31, 2005. Of the remaining 42%, 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.

We estimate the capital costs required to develop all of our proved undeveloped reserves will be $380.6 million (not including plug and abandonment costs). We plan to develop approximately 32% of our existing proved undeveloped reserves during the next three years at an estimated cost of $325.4 million. The remaining 68% are waiting on either proved producing wells to deplete in order to use the well bore or will be reclassified to behind pipe following the completion of the proved undeveloped projects scheduled over the next three years. However, we are not the operator of 25% of our proved undeveloped reserves, so we are not in a position to guarantee the precise timing or costs of developing these 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, 2005 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 3.1% 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 2005 were approximately 33% lower on average than prices for equivalent volumes of oil and average prices have been 31% 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.

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. Upon adoption of SFAS No. 143 on January 1, 2003, we recorded an increase in net property and equipment of $95.0 million and recognized an initial asset retirement obligation of $101.7 million and a cumulative effect of adoption that increased net income and shareholders’ equity by $0.1 million, net of income tax.

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.

Stock−based compensation. In October 1995, the FASB issued SFAS No. 123, *Accounting for Stock−Based Compensation*. The standard encourages, but does not require, companies to record compensation cost for stock−based employee compensation plans at fair value. We have elected to account for stock−based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Accordingly, compensation cost for stock issued is measured as the excess, if any, of the fair value of our common stock at the date of the grant over the amount an employee must pay to acquire the common stock.

New Accounting Policies and Pronouncements

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106, which expressed the Staff's views regarding the application of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, by oil and gas companies following the full cost method of accounting. SAB No. 106 indicates that estimated dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves, and have not been accrued under SFAS No. 143, should be included in the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. SAB No. 106 also indicates that these estimated costs should be included in the costs to be amortized. Effective January 1, 2005, we began applying the requirements of SAB No. 106, which did not have a material effect on our consolidated financial statements.

In December 2004, the FASB issued FASB Staff Position ("FSP") FAS 109−1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*. FSP FAS 109−1 provided guidance on the application of SFAS No. 109, *Accounting for Income Taxes,* to the tax deduction on "qualified production activities." This deduction was available beginning in 2005 and did not have a material impact on our effective income tax rate for the year ended December 31, 2005.

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), *Share−Based Payment*, that establishes standards for the accounting of transactions in which an entity exchanges its equity instruments for goods or services or incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123(R) focuses primarily on accounting for transactions in which an entity obtains employee services in share−based payment transactions and requires public entities to measure the cost of employee services received in exchange for an award of equity instruments based on the grant−date fair value of the award (with limited exceptions) and recognize the cost over the period during which an employee is required to provide service in exchange for the award. SFAS No. 123(R) eliminates the alternative use of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123(R) was originally effective for us beginning July 1, 2005; however, in April 2005, the SEC issued press release 2005−57, which extended the implementation date of SFAS No. 123(R) such that SFAS No. 123(R) is now effective for us beginning January 1, 2006. During the third quarter of 2005, the FASB continued to issue new and proposed guidance related to SFAS No. 123(R). Since our previous share−based payments have been recorded at fair value and since we currently have no stock options outstanding, we do not expect the adoption of SFAS No. 123(R) will have an impact 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 decline 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, our 2005 income before income taxes would have declined by approximately 20%. If costs and expenses of operating our properties had increased by 10% in 2005, our income before income taxes would have declined by approximately 3%.

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, 2005. Interest rate changes will impact future results of operations and cash flows. Assuming the same average borrowings, a 100 basis point increase in interest rates would have a nominal effect on our 2005 interest expense.

Hedging. We did not enter into any hedging transactions during the years ended December 31 2005, 2004 and 2003. As discussed in Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Events—Transaction with Kerr−McGee"* and Note 21 to our consolidated financial statements, in January 2006 we entered into certain commodity price hedges in connection with the anticipated financing related to a pending acquisition of oil and gas properties from Kerr−McGee.

Index to Financial Statements

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

W&T OFFSHORE, INC. AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENTS

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 (the "Company") as of December 31, 2005 and 2004, 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, 2005. These consolidated 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management and 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 as of December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

/s/ ERNST & YOUNG LLP

New Orleans, Louisiana
March 30, 2006

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 187,698	$ 64,975
Receivables:		
Oil and gas sales	43,892	40,427
Joint interest and other	39,731	22,165
Income taxes	—	9,122
Total receivables	83,623	71,714
Royalty deposits	5,166	5,166
Prepaid expenses and other assets	7,337	4,127
Total current assets	283,824	145,982
Property and equipment—at cost:		
Oil and gas properties and equipment—full cost method of accounting	1,479,832	1,140,740
Furniture, fixtures and other	7,033	6,627
Total property and equipment	1,486,865	1,147,367
Less accumulated depreciation, depletion and amortization	717,583	543,154
Net property and equipment	769,282	604,213
Restricted deposits for asset retirement obligations	10,348	10,072
Deferred financing costs, less accumulated amortization of $1,282 and $940 in 2005 and 2004, respectively	1,066	517
Total assets	$ 1,064,520	$ 760,784
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 143,049	$ 107,220
Undistributed oil and gas proceeds	11,667	13,286
Asset retirement obligations	39,653	27,489
Accrued liabilities	5,714	8,452
Income taxes	31,609	—
Total current liabilities	231,692	156,447
Long−term debt	40,000	35,000
Asset retirement obligations, less current portion	112,621	114,937
Deferred income taxes	134,395	92,093
Other liabilities	2,429	2,429
Commitments and contingencies		
Shareholders' equity:		
Series A preferred stock, $0.00001 par value; 2,000,000 shares authorized; issued and outstanding none and 2,000,000 shares at December 31, 2005 and 2004, respectively	—	45,435
Common stock, $0.00001 par value; authorized 118,330,000 shares, issued and outstanding 65,979,875 and 52,611,674 shares at December 31, 2005 and 2004, respectively	1	—
Additional paid−in capital	52,332	6,478
Retained earnings	491,050	307,965
Total shareholders' equity	543,383	359,878
Total liabilities and shareholders' equity	$ 1,064,520	$ 760,784

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2005	2004	2003
	(In thousands, except per share data)		
Revenues:			
Oil and gas revenues	$584,564	$508,195	$421,435
Other	572	520	1,152
Total revenues	585,136	508,715	422,587
Operating costs and expenses:			
Lease operating	71,758	73,475	65,947
Production taxes	712	375	303
Gathering and transportation	11,990	13,724	9,910
Depreciation, depletion and amortization	174,771	155,640	136,249
Asset retirement obligation accretion	9,062	9,168	7,443
General and administrative	28,418	25,001	22,912
Total costs and expenses	296,711	277,383	242,764
Operating income	288,425	231,332	179,823
Other income (expense):			
Interest and dividend income	2,746	276	279
Interest expense	(1,145)	(2,118)	(2,508)
Total other income (expense)	1,601	(1,842)	(2,229)
Income before income taxes	290,026	229,490	177,594
Income taxes	101,003	80,008	61,156
Income before cumulative effect of change in accounting principle	189,023	149,482	116,438
Cumulative effect of change in accounting principle (net of tax of $77)	—	—	144
Net income	189,023	149,482	116,582
Less preferred stock dividends	—	900	5,876
Net income applicable to common shares	$189,023	$148,582	$110,706
Basic net income per common share:			
Income before cumulative effect of change in accounting principle	$ 2.91	$ 2.82	$ 2.14
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 2.91	$ 2.82	$ 2.14
Diluted net income per common share:			
Income before cumulative effect of change in accounting principle	$ 2.87	$ 2.27	1.79
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 2.87	$ 2.27	1.79

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

	Preferred		Common				
	Shares	Value	Shares	Value	Additional Paid−In Capital	Retained Earnings	Total Shareholders' Equity
	(In thousands, except per share data)						
Balances at January 1, 2003	2,000	$ 45,435	50,696	$ —	$ 544	$ 87,351	$ 133,330
Cash dividends:							
Common stock ($0.67 per share)	—	—	—	—	—	(35,124)	(35,124)
Preferred stock ($2.94 per share)	—	—	—	—	—	(5,876)	(5,876)
Common stock issued	—	—	1,821	—	5,543	—	5,543
Net income	—	—	—	—	—	116,582	116,582
Balances at December 31, 2003	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

See accompanying notes.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Operating activities:			
Net income	$ 189,023	$ 149,482	$ 116,582
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	183,833	164,808	143,692
Amortization of debt issuance costs	342	461	442
Share−based compensation	419	391	5,543
Loss (gain) on disposal of equipment	11	—	(182)
Cumulative effect of change in accounting principle, net of tax	—	—	(144)
Deferred income taxes	42,302	40,189	1,660
Changes in operating assets and liabilities:			
Oil and gas receivables	(3,465)	(1,320)	(16,090)
Joint interest receivables and other	(17,566)	2,019	(3,998)
Income taxes	40,731	(25,410)	14,046
Prepaid expenses, royalty deposits and other assets	(3,211)	(2,397)	(3,012)
Asset retirement obligations	(17,868)	(12,857)	(9,181)
Accounts payable and accrued liabilities	29,492	59,481	13,797
Other liabilities	—	2,428	—
Net cash provided by operating activities	444,043	377,275	263,155
Investing activities:			
Investment in oil and gas property and equipment	(322,984)	(282,510)	(201,318)
Proceeds from sales of oil and gas property and equipment	2,547	3,127	173
Purchases of furniture, fixtures and other	(759)	(2,337)	(2,082)
Proceeds from the sale of subsidiary	—	—	1,000
Change in restricted deposits	(277)	1,854	(2,175)
Net cash used in investing activities	(321,473)	(279,866)	(204,402)
Financing activities:			
Borrowings of long−term debt	42,550	212,100	253,200
Repayments of borrowings of long−term debt	(37,550)	(244,100)	(285,800)
Dividends to shareholders	(3,958)	(4,450)	(41,000)
Debt issuance costs	(889)	—	(91)
Net cash provided by (used in) financing activities	153	(36,450)	(73,691)
Increase (decrease) in cash and cash equivalents	122,723	60,959	(14,938)
Cash and cash equivalents, beginning of period	64,975	4,016	18,954
Cash and cash equivalents, end of period	$ 187,698	$ 64,975	$ 4,016

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 and exploration 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 wholly owned subsidiaries. Effective January 2, 2003 we sold our 99% ownership interest in W&T Offshore, LLC (see Notes 5 and 16). All significant intercompany transactions and amounts have been eliminated for all years presented.

Use of Estimates and Market Risk

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.

Our future financial condition and results of operations will depend upon prices received for our oil and natural gas production and the costs of finding, acquiring, developing and producing reserves. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond our control. These factors include worldwide political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand and the price and availability of alternative fuels.

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

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and if the collection of the revenue is probable. We use the sales method of accounting for our oil and gas revenues. Under this method of accounting, revenue is recorded based upon our physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under−produced party to recoup its entitled share through production. As of December 31, 2005 and 2004, deliveries of natural gas in excess of our revenue interest and under−deliveries 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.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

Customer	Year Ended December 31, 2005	2004	2003
Shell Trading (US) Company	21%	21%	18%
BP Amoco	19%	22%	13%
Cinergy Corp.	18%	**	**
ConocoPhillips	17%	20%	46%

** 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 reserves, including directly related overhead costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include costs of drilling exploratory wells and geological and geophysical costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, including certain geological and geophysical costs and general and administrative costs are expensed in the period incurred.

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.

Amortization of capitalized oil and gas properties is calculated 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. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on nonproducing properties, costs of drilling both productive and nonproductive wells and overhead charges directly related to acquisition, exploration and development activities.

We capitalize interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that exploration and development activities are in progress. We have not excluded any expenditures related to our oil and gas properties from amortization and have not capitalized any interest during the years ended December 31, 2005, 2004 or 2003.

Under the full cost method of accounting, we are required to periodically perform a “ceiling test,” which compares the present value of estimated future net cash flows from proved reserves (based on period−end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write−down the value of our oil and gas properties to the value of the discounted cash flows. We did not have a ceiling test impairment during the years ended December 31, 2005, 2004 or 2003.

Furniture, fixtures and non−oil and gas property and equipment are depreciated using the straight−line method based on the estimated useful life of the respective assets. 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.

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 regulations 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

Costs incurred in connection with the issuance of long−term debt are capitalized and amortized to interest expense over the scheduled maturity of the debt utilizing the interest method.

Stock−Based Compensation

SFAS No. 123, *Accounting for Stock−Based Compensation*, encourages but does not require, companies to record compensation costs for stock−based employee compensation plans at fair value. We have chosen to account for stock−based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting For Stock Issued to Employees* ("APB No. 25"), and related interpretations. Accordingly, compensation cost for stock issued is measured as the excess, if any, of the fair value of our common stock at the date of the grant over the amount an employee must pay to acquire the common stock.

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 was calculated by dividing net income applicable to common shares, adjusted for preferred stock dividends, by the weighted average common shares outstanding during the periods presented, increased, however, to include the number of additional common shares that could have been outstanding assuming the conversion of all of the preferred stock.

Recent Accounting Developments

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), Share−Based Payment, that establishes standards for the accounting of transactions in which an entity exchanges its equity instruments for goods or services or incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123(R) focuses primarily on accounting for transactions in which an entity obtains employee services in share−based payment transactions and requires public entities to measure the cost of employee services received in exchange for an award of equity instruments based on the grant−date fair value of the award (with limited exceptions) and recognize the cost over the period during which an employee is required to provide service in exchange for the award. SFAS No. 123(R) eliminates the alternative use of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123(R) was originally effective for us beginning July 1, 2005; however, in April 2005, the SEC issued press release 2005−57, which extended the implementation date of SFAS No. 123(R) such that SFAS No. 123(R) is now effective for us beginning January 1, 2006. During the third quarter of 2005, the FASB continued to issue new and proposed guidance related to SFAS No. 123(R). Since our previous share−based payments have been recorded at fair value and since we currently have no stock options outstanding, we do not expect the adoption of SFAS No. 123(R) will have an impact on our consolidated financial statements.

2. Initial Public Offering

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, all 2,000,000 shares of the Company's preferred stock were converted into a total of 13,338,350 shares of our common stock.

3. 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.

We adopted SFAS No. 143 as of January 1, 2003, which resulted in an increase to net oil and gas properties of $95.0 million and additional liabilities related to asset retirement obligations of $101.7 million. These amounts reflect our ARO had the provisions of SFAS No. 143 been applied since inception and resulted in a non−cash cumulative effect increase to earnings of approximately $0.2 million ($0.1 million net of tax). In accordance with the provisions of SFAS No. 143, we record an abandonment liability associated with our oil and gas wells and platforms when those assets are placed in service.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following is a reconciliation of our asset retirement obligation liability as of December 31, 2005 and 2004 (in millions).

	2005	2004
Asset retirement obligation, beginning of period	$142.4	$127.6
Liabilities settled	(17.9)	(12.9)
Accretion expense	9.1	9.2
Liabilities incurred, net of sales	5.9	14.7
Revision in estimated cash flows (1)	12.8	3.8
Asset retirement obligation, end of period	$152.3	$142.4

(1) Includes approximately $7.7 million resulting from revisions to estimates and acceleration of the expected timing of asset retirement obligation settlements associated with facilities damaged by Hurricane Rita in 2005.

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106, which expressed the Staff's views regarding the application of SFAS No. 143 by oil and gas companies following the full cost method of accounting. SAB No. 106 indicates that estimated dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves, and have not been accrued under SFAS No. 143, should be included in the computation of the present value of estimated future net revenues for purposes of the full cost ceiling test. SAB No. 106 also indicates that these estimated costs should be included in the costs to be amortized. As of January 1, 2005, we began applying the requirements of SAB No. 106, which did not have a material effect on our consolidated financial statements.

4. Restricted Deposits

Restricted deposits as of December 31, 2005 and 2004 consisted of funds escrowed for the future plug and abandonment of certain oil and gas properties. In connection with properties acquired in 2002, we received approximately $9.6 million in escrowed funds attributable to the future plug and abandonment of two oil and gas fields. We are currently not obligated to contribute additional amounts to further fund these escrowed accounts.

In connection with the ConocoPhillips Acquisition in 2003 as discussed in Note 6, we provided the U.S. Minerals Management Service with a $1.8 million U.S. Treasury note in satisfaction of mandatory area−wide operator bonding requirements. In 2005, the U.S. Treasury note was released to us and we executed surety bonds to satisfy these bonding requirements.

5. Sale of Subsidiary

On January 2, 2003, we sold our 99% ownership interest in W&T Offshore, LLC to our two largest common shareholders for $1 million in cash (see Note 16). The sales price was determined by management to approximate fair value.

6. Significant Acquisitions

In December 2003, we acquired substantially all of ConocoPhillips' Gulf of Mexico shelf assets (the "ConocoPhillips Acquisition"). This acquisition was accounted for as a purchase in accordance with SFAS No. 141, *Business Combinations*. The results of operations from this acquisition have been included in the accompanying statements of income since the closing date.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following unaudited pro forma information shows the effect on our consolidated results of operations as if the ConocoPhillips Acquisition occurred on January 1, 2003. The pro forma information includes only significant acquisitions and numerous assumptions and is not necessarily indicative of future results of operations (in thousands).

	Year Ended December 31, 2003	
	Audited	Pro Forma (Unaudited)
Oil and gas revenues	$ 421,435	$ 502,140
Income before income taxes and cumulative effect of a change in accounting principle	$ 177,594	$ 234,287
Net income before income taxes	$ 177,738	$ 234,431
Net income	$ 116,582	$ 153,432

7. Equity Structure and Transactions

At December 31, 2001, our capital structure consisted of 100,000 authorized shares of common stock, of which 3,900 shares were issued and outstanding. In late 2002, we repurchased and retired 300 shares of common stock and purchased a less than 1% interest in W&T Offshore, LLC from a shareholder for $15 million in cash. In a transaction with a third party, the same shareholder sold his remaining 1,000 shares of our common stock for $50 million. Contemporaneously, we executed an Exchange Agreement with the third−party purchaser pursuant to which the purchaser tendered the 1,000 shares of common stock in exchange for two million shares of our Series A Preferred Stock (“Preferred Stock”), having a face amount of $50 million.

Upon the completion of the Exchange Agreement, we were recapitalized and declared a 2,911.48115−for−one stock dividend on our remaining 2,600 outstanding shares of common stock. The recapitalization resulted in 20 million shares of capital stock, of which 18 million were designated as common stock, with a par value per share of $0.00001, and two million shares designated as preferred stock, with a par value per share of $0.00001.

A special dividend in the aggregate amount of $12 million was authorized for holders of record immediately preceding the issuance of the Preferred Stock on December 3, 2002. The special dividend was paid during the second quarter of 2003.

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”.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

8. Long−Term Debt

On March 15, 2005, we entered into a new $300 million secured revolving credit facility with an initial borrowing base of $230 million, which is subject to redetermination on March 1 and September 1 of each year. The new revolving line of credit matures on March 15, 2009 and is secured by substantially all of our oil and gas properties. 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 0.625% depending upon the ratio of the amounts outstanding to the borrowing base 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 1.875%, depending upon the ratio of the amounts outstanding to the borrowing base. At December 31, 2005, the Borrowing Base amount was $230 million, the outstanding loan balance on the revolving line of credit was $40 million, excluding $0.3 million outstanding letters of credit, and the available line of credit was $189.7 million.

Our credit agreement contains covenants that restrict the payment of cash dividends to a maximum of $30 million per year, borrowings other than from our credit facility, 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 also subject to various financial covenants, including a minimum tangible net worth ratio, a minimum current ratio and a minimum interest coverage ratio. We were in compliance with these covenants on December 31, 2005.

9. 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,	
	2005	2004
Deferred tax liabilities:		
Oil and gas properties and equipment	$ 135,298	$ 93,516
Change in tax accounting method	—	962
Total deferred tax liabilities	135,298	94,478
Deferred tax assets—accruals	903	2,385
Net deferred tax liabilities	$ 134,395	$ 92,093

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

	Year Ended December 31,		
	2005	2004	2003
Current	$ 57,037	$ 39,819	$ 59,418
Deferred	43,966	40,189	1,738
	$ 101,003	$ 80,008	$ 61,156

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

	Year Ended December 31,					
	2005		2004		2003	
Income before income taxes	$290,026		$229,490		$177,594	
Income tax expense at the federal statutory rate	$101,509	35.0%	$ 80,322	35.0%	$ 62,158	35.0%
Permanent and other	(506)	(0.2)%	(314)	0.0%	(1,002)	(0.6)%
	$101,003	34.8%	$ 80,008	35.0%	$ 61,156	34.4%

In December 2004, the FASB issued FASB Staff Position ("FSP") FAS 109−1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*. FSP FAS 109−1 provided guidance on the application of SFAS No. 109, *Accounting for Income Taxes*, to the tax deduction on "qualified production activities." This deduction was available beginning in 2005 and did not have a material impact on our effective income tax rate for the year ended December 31, 2005.

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, 2006, the Internal Revenue Service further postponed tax deadlines with a due date falling on or after August 29, 2005 until August 28, 2006 for taxpayers affected by Hurricane Katrina. Consequently, our estimated federal income tax payments due on September 15, 2005 and December 15, 2005 were deferred to a date on or about August 28, 2006 and we anticipate that we will elect to defer our estimated federal income tax payments due in the second quarter of 2006 to such date in August 2006.

10. Commitments

We have operating lease agreements for office space, which terminate in August 2011. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2005 are as follows (in millions): $1.1–2006, $1.7–2007, $1.6–2008, $1.0–2009, $0.9–2010, $0.7–Thereafter.

Total rent expense was approximately $0.8 million, $0.9 million and $0.6 million during the years ended December 31, 2005, 2004 and 2003, 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.

11. 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.

12. Hurricanes Katrina and Rita

During the third quarter of 2005, Hurricanes Katrina and Rita caused property damage and disruptions to our exploration and production activities. We have notified our insurance underwriters of our potential losses and that we will file claims for damages caused by these hurricanes. We do not carry business interruption insurance. We have been assigned and have been working with an adjuster and are evaluating and documenting the hurricane damage. We currently estimate the total cost to repair damages to our facilities caused by Hurricanes Katrina and Rita will range from $60 million to $75 million. As of December 31, 2005 we have incurred $11.6 million of costs to remediate damage caused by Hurricanes Katrina and Rita. Our insurance policy covering physical damage has a cumulative annual deductible of $5 million that must be satisfied before we are indemnified for losses. Of this amount, $1.6 million is included in lease operating expenses and $3.4 million is included in oil and gas properties. The costs we have incurred in excess of our deductible, or $6.6 million, is included in joint interest and other receivables.

We believe that our insurance coverage is adequate to cover losses associated with Hurricanes Katrina and Rita and are not aware of any reason why coverage may be limited or denied; however, it is possible that the insurance companies may contest our claims. We expect that our available cash and cash equivalents, cash flow from operations and the availability of our credit facility will be sufficient to meet any uninsured expenditures.

13. 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. For 2005 and 2004, the Company matching contribution was 100% of each participant's contribution up to a maximum of 5% of the participant's compensation, subject to Code limitations. In 2003, employee contributions were matched up to a maximum of 25% of the first 5% of the participant's compensation, subject to Code limitations. We may also elect to make additional contributions in an amount determined by our board of directors. Our expenses relating to the 401(k) Plan were approximately $0.7 million, $0.5 million and $0.1 million for the years ended December 31, 2005, 2004 and 2003, respectively.

14. Long−Term Incentive Compensation Plan

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 the Chief Executive Officer) who, by written agreement, have elected not to participate. Under the 2005 Plan, eligible employees earn cash bonuses and awards of restricted stock under the Plan 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. Bonuses for 2005 are payable on or before April 2, 2006. In 2005, we expensed $2.2 million related to the cash portion of the general bonus.

During 2005, 2004 and 2003, we issued 29,851 shares, 95,118 shares and 1,820,594 shares, respectively, of common stock to employees pursuant to the terms of the plans. In accordance with APB No. 25, compensation cost related to the stock awards was $0.4 million, $0.4 million and $5.5 million for the years ended December 31, 2005, 2004 and 2003, respectively. These amounts are included in general and administrative expenses. As of December 31, 2005, there are 1,637,442 shares of common stock available for award under the Plan (see Note 1—*Recent Accounting Developments*).

15. Earnings Per Share

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,		
	2005	2004	2003
Net income applicable to common shares	$ 189,023	$ 148,582	$ 110,706
Add preferred stock dividends	—	900	5,876
Adjusted net income applicable to common shares	$ 189,023	$ 149,482	$ 116,582
Weighted average number of common shares (basic)	64,982	52,604	51,699
Weighted average common shares assumed issued upon conversion of the preferred stock	989	13,338	13,338
Weighted average number of common shares (diluted)	65,971	65,942	65,037
Net income applicable to common shares:			
Basic	$ 2.91	$ 2.82	$ 2.14
Diluted	$ 2.87	$ 2.27	$ 1.79

16. 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.

The grandson of Jerome F. Freel, a director and our Corporate Secretary, is employed by an insurance agency that writes certain insurance coverage for the Company. Personal commissions earned by the grandson for writing such coverage totaled approximately $51,000 and $47,000 in 2005 and 2004, respectively. Business was awarded to this insurance agency as low bidder in a competitive bidding process in which the Company received at least one other quote.

Effective January 1, 2003 we sold our 99% ownership interest in W&T Offshore, LLC ("W&T LLC") to Tracy W. Krohn and Jerome F. Freel, our two largest common shareholders, who are also our officers and directors (see Note 6). We continued to provide management services, including land, geological, accounting, engineering and administrative services for W&T LLC for which we received no compensation in 2003. We executed a management agreement with W&T LLC under which we received approximately $0.1 million for providing management services to W&T LLC during each of the years of 2005 and 2004. These fees are recorded as a direct reduction of general and administrative expenses.

During 2005, Tracy W. Krohn, our Chief Executive Officer, reimbursed the Company $0.4 million for personal use in 2005 of an aircraft in which we own a fractional interest.

We utilize the services of an employment placement firm owned by Susan Krohn, the wife of Tracy W. Krohn. We incurred approximately $0.2 million, $0.4 million and $0.3 million in fees paid to this firm during the years ended December 31, 2005, 2004 and 2003, respectively.

During 2003, we purchased oilfield goods, services and equipment from a drilling and production company, which was majority−owned by Joseph P. Slattery, one of our executives, and his wife. During the year ended December 31, 2003, we incurred expenses of approximately $2.2 million with this company. The Slatterys sold their interest in the drilling and production company effective December 31, 2003.

During 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.

17. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2005	2004	2003
Cash flow information:			
Cash paid for interest expense	$ 791	$ 1,692	$ 2,111
Cash paid for income taxes	17,969	65,229	45,450

18. Oil and Gas Properties and Equipment

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

	December 31,		
	2005	2004	2003
Net capitalized cost:			
Proved oil and natural gas properties	$1,238.1	$ 949.2	$ 712.9
Unproved oil and natural gas properties	90.3	58.9	16.2
Capitalized asset retirement obligations	151.4	132.7	113.7
Accumulated depreciation, depletion and amortization	(714.6)	(541.1)	(386.3)
	$ 765.2	$ 599.7	$ 456.5

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	Year Ended December 31,		
	2005	2004	2003
Costs incurred:			
Proved property acquisitions	$ 16.9	$ 33.5	$ 69.1
Development	174.6	90.7	65.1
Exploration	122.1	150.4	54.5
Unproved property acquisitions	9.4	7.9	13.4
Asset retirement obligations	18.7	18.5	27.6
	$ 341.7	$ 301.0	$ 229.7

	Year Ended December 31,		
	2003	2004	2005
Depreciation, depletion, amortization and accretion per Mcfe	$ 2.59	$ 2.00	$ 1.82

19. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2005 and 2004 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
Net income per common share: (1)				
Basic	0.63	0.69	0.80	0.77
Diluted	0.60	0.69	0.80	0.77
Year Ended December 31, 2004				
Revenues	$ 123,267	$ 126,059	$ 120,534	$ 138,855
Operating income	59,124	53,950	58,920	59,338
Net income	38,043	34,710	38,053	38,676
Net income per common share: (1)				
Basic	0.72	0.65	0.72	0.73
Diluted	0.58	0.53	0.58	0.59

(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. Oil and Gas Reserve Information—UNAUDITED

Our net proved oil and gas reserves at December 31, 2005, 2004 and 2003 have been estimated by 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.

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

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 and offshore in the continental United States.

	Oil (MBbls)	Natural Gas (MMcf)
Proved reserves as of January 1, 2003	23,082	219,039
Revisions of previous estimates (1)	1,780	(17,226)
Extensions, discoveries and other additions	3,687	26,470
Purchase of producing properties	11,426	55,585
Production	(4,373)	(52,807)
Proved reserves as of December 31, 2003	35,602	231,061
Revisions of previous estimates	2,351	6,770
Extensions, discoveries and other additions	4,582	37,732
Purchase of producing properties	2,294	5,464
Sales of reserves	(1)	(106)
Production	(4,847)	(53,348)
Proved reserves as of December 31, 2004	39,981	227,573
Revisions of previous estimates	2,456	5,546
Extensions, discoveries and other additions	5,920	25,120
Purchase of producing properties	1,665	4,229
Production	(4,085)	(46,548)
Proved reserves as of December 31, 2005	45,937	215,920
Year−end proved developed reserves:		
2005	24,773	169,995
2004	20,311	168,260
2003	19,718	177,263

(1) Approximately 48% of the 17,226 downward revision in 2003 was made when the owner of a production platform on which the production from our well was being processed decided to shut down the platform.

The following presents the standardized measure of 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 plug and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2005, 2004 and 2003 in accordance with SFAS No. 143. Average year−end prices related to proved reserves of natural gas were $10.15, $6.31 and $6.07 per Mcf and for oil were $54.55, $39.05 and $29.00 per barrel at December 31, 2005, 2004 and 2003. Future production and development costs are based on current costs with no escalations. Estimated future 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 2006 or later years and the risks inherent in reserve estimates. The standardized

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

measure of discounted future net cash flows relating to our proved oil and gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 4,697,926	$ 2,998,214	$ 2,435,234
Future costs:			
Production	(504,741)	(467,784)	(425,275)
Development	(433,572)	(277,905)	(246,853)
Dismantlement and abandonment	(220,943)	(204,626)	(180,924)
Future net cash flows before income taxes	3,538,670	2,047,899	1,582,182
Future income taxes	(1,146,073)	(646,418)	(503,283)
Future net cash inflows before 10% discount	2,392,597	1,401,481	1,078,899
10% annual discount factor	(796,151)	(426,693)	(317,960)
	$ 1,596,446	$ 974,788	$ 760,939

	Year Ended December 31,		
	2005	2004	2003
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 974,788	$ 760,939	$ 549,651
Sales and transfers of oil and gas produced, net of production costs	(500,676)	(421,142)	(346,244)
Net changes in price, net of future production costs	900,738	256,315	151,242
Extensions and discoveries, net of future production and development costs	224,965	257,206	59,882
Changes in estimated future development costs (including plug and abandonment costs)	(143,296)	(76,704)	(27,030)
Development costs incurred during the period (including plug and abandonment costs)	192,475	103,653	73,569
Revisions of quantity estimates	113,390	78,371	35,875
Accretion of discount	129,387	100,580	80,580
Net change in income taxes	(315,100)	(94,649)	(98,816)
Purchases of reserves in−place	91,306	58,152	285,781
Sales of reserves in−place	—	(524)	—
Changes in production rates due to timing and other	(71,531)	(47,409)	(3,551)
Net increase in standardized measure	621,658	213,849	211,288
Standardized measure, end of year	$ 1,596,446	$ 974,788	$ 760,939

21. Subsequent Events—UNAUDITED

Transaction with Kerr−McGee

On January 23, 2006, we entered into an agreement with Kerr−McGee Oil & Gas Corporation to acquire a subsidiary of Kerr−McGee by merger. We will own the surviving entity, which will be the successor to substantially all of Kerr−McGee's Gulf of Mexico conventional shelf properties. Base consideration for the transaction is approximately $1.3 billion in cash. The merger transaction is expected to close during the second or third quarter of 2006, subject to regulatory review and customary closing conditions and adjustments. The properties we will acquire by this merger include interests in approximately 100 fields on 249 offshore blocks (including 83 undeveloped blocks) and most of the properties are in water depths of 500 feet or less. We expect to finance the transaction with bank debt and cash on hand. We have received financing commitments from certain financial institutions for up to a $1.3 billion senior secured credit facility. Closing of the financing will be subject to customary conditions, including the parties entering into definitive documentation.

In connection with the anticipated financing of the transaction with Kerr−McGee, in January 2006, we entered into the following commodity price hedges.

Options

Option Type	Commodity	Effective Date	Termination Date	Notional Quantity	Strike Price Put	Strike Price Call
Zero Cost Collar	Natural Gas	4/1/2006	6/30/2006	4,823,000 MMBtu	$ 7.14	$12.65
Zero Cost Collar	Natural Gas	7/1/2006	9/30/2006	2,116,000 MMBtu	7.32	13.10
Zero Cost Collar	Natural Gas	10/1/2006	12/31/2006	3,036,000 MMBtu	8.04	14.49
Collar	Natural Gas	1/1/2007	12/31/2007	8,760,000 MMBtu	7.76	16.80
Zero Cost Collar	Oil	1/1/2007	12/31/2007	1,569,500 Bbls	61.68	76.40
Collar	Natural Gas	1/1/2008	12/31/2008	5,124,000 MMBtu	7.31	15.80
Zero Cost Collar	Oil	1/1/2008	12/31/2008	1,024,800 Bbls	60.00	74.50

Swaps

Commodity	Effective Date	Termination Date	Notional Quantity	Swap Price
Oil	4/1/2006	6/30/2006	364,000 Bbls	$69.33
Oil	7/1/2006	9/30/2006	165,600 Bbls	69.72
Oil	10/1/2006	12/31/2006	248,400 Bbls	69.85

2005 Bonus Award

In March 2006, our board of directors approved payment of a general bonus and an extraordinary bonus for 2005 under our incentive compensation plan. Although not all of the performance measures for the extraordinary bonus were met, our board determined that substantially all of the performance measures would have been met were it not for the effects of Hurricanes Katrina and Rita. The total cash portion of the 2005 general bonus is $2.8 million, of which $2.2 million has been expensed in 2005. The total cash portion of the extraordinary bonus is $1.4 million and will be expensed in the first quarter of 2006. The total restricted stock portion of the general bonus is $4.0 million and the total restricted stock portion of the extraordinary bonus is $2.0 million. The restricted stock will vest in three equal increments on December 31 of 2006, 2007 and 2008, and the associated compensation expense will be recognized over the vesting period. A total of 160,377 restricted shares were granted in connection with the 2005 bonuses.

Dividend

On March 13, 2006, the Company's board of directors declared a cash dividend of $0.03 per share of common stock, payable on May 1, 2006 to shareholders of record on April 14, 2006.

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

None

Item 9A. ***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, 2005 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.

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2005 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 and Executive Officers of the Registrant***

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***

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:

All other 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)

Exhibit Number	Description
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	Employment Agreement dated October 3, 2005, by and between Stephen A. Landry and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8−K/A, dated October 19, 2005)
10.8	Indemnification and Hold Harmless Agreement dated October 19, 2005 by and between Stephen A. Landry of the Company. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8−K/A, dated October 19, 2005)
10.9	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)
10.10*	Indemnification and Hold Harmless Agreement dated January 20, 2006, by and between S. James Nelson, Jr. and the Company.
10.11	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))
10.12	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))
10.13	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))
10.14	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)
10.15	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))
10.16	Agreement and Plan of Merger Among Kerr−McKee 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)
10.17	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)
10.18	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)
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.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of 6 Mcf of natural gas to 1 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.

Outer continental shelf (OCS) block. A unit of defined area for purposes of management of offshore petroleum exploration and production by the Minerals Management Service.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

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.

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.

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.

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 31, 2006.

W&T OFFSHORE, INC.

By: /S/ WILLIAM W. TALAFUSE

William W. Talafuse
Senior Vice President,
interim Chief Financial Officer and
Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 31, 2006.

/S/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Treasurer and Director (Principal Executive Officer)
/S/ WILLIAM W. TALAFUSE **William W. Talafuse**	Senior Vice President, interim Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)
/S/ VIRGINIA BOULET **Virginia Boulet**	Director
/S/ JEROME F. FREEL **Jerome 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

INDEMNIFICATION AND HOLD HARMLESS AGREEMENT

THIS INDEMNIFICATION AND HOLD HARMLESS AGREEMENT (this "Agreement") is made as of January 20, 2006, by and between W&T Offshore, Inc., a Texas corporation (the "Company"), and S. James Nelson, Jr. ("Indemnitee").

WHEREAS, in order to incentivize Indemnitee to serve, or to continue to serve, as a director of the Company (in any such case, the "Service"), the Company has agreed to indemnify Indemnitee as set forth below;

NOW, THEREFORE, in consideration of the foregoing and certain other good and valuable consideration, the receipt of which is hereby acknowledged, the parties, intending to be legally bound, hereby agree as follows:

1. Indemnification. Effective as of the original date of Indemnitee's beginning Service, the Company shall indemnify Indemnitee and hold Indemnitee harmless if the Indemnitee is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative, arbitrative or investigative, and in any appeal in such action, suit or proceeding, and in any inquiry or investigation that could lead to such an action, suit or proceeding, against any and all liabilities, obligations (whether known or unknown, or due or to become due or otherwise), judgments, fines, fees, penalties, interest obligations, deficiencies, other actual losses (for example, verifiable lost income related to time spent defending such claim or action) and reasonable expenses (including, without limitation amounts paid in settlement, interest, court costs, costs of investigators, reasonable fees and expenses of attorneys, accountants, financial advisors and other experts) incurred or suffered by Indemnitee in connection with such action, suit or proceeding arising out of or pertaining to any actual or alleged action or omission which arises out of or relates to the fact that Indemnitee is or was serving as a director or officer of the Company or at the request of the Company as a director, officer, trustee, employee, or agent of or in any other capacity for another corporation, partnership, joint venture, trust or other enterprise, to the fullest extent permitted by then applicable law and the Company's Articles of Incorporation and Bylaws, each as amended (but in the case of any such amendment, only to the extent that such amendment permits the Company to provide the same or broader indemnification rights than permitted prior thereto) (each such liability, obligation, judgment, fine, fee, penalty, interest obligation, deficiency, other actual losses, and reasonable expenses being referred to herein as a "Loss," and collectively, as "Losses").

2. Payment. Any Loss incurred by Indemnitee shall be paid in full by the Company on a regular, monthly basis. This indemnity applies even if the Indemnitee caused the Loss through his or her negligence, strict liability or other fault; however, if any Losses for which Indemnitee received payment from the Company under this Agreement are determined by final judicial decision from which there is no further right to appeal, to have been caused by Indemnitee under circumstances with respect to which indemnification is not permitted by applicable law or this Agreement (any such Loss, a "Non−Indemnification Loss"), Indemnitee shall repay to the Company such Losses paid on behalf of Indemnitee hereunder.

3. Term. The indemnification rights provided hereby to Indemnitee shall continue even though he or she may have ceased to be a director, officer, trustee, employee, or agent of or in any other capacity for the applicable entity.

4. Notice and Coverage Prior to Notice. Indemnitee shall give notice (the "Notice") to the Company within five days after actual receipt of service or summons related to any action begun in respect of which indemnity may be sought hereunder or actual notice of assertion of a claim with respect to which he seeks indemnification; provided, however, that the Indemnitee's failure to give such notice to the Company within such time shall not relieve the Company from any of its obligations under Section 1 of this Agreement except to the extent the Company has been materially prejudiced by Indemnitee's failure to give such notice within such time period. Upon receipt of the Notice, the Company shall assume the defense of such action, whereupon the Indemnitee shall not be liable for any reasonable fees or expenses of counsel for Indemnitee or any other Losses incurred thereafter with respect to the matters set forth in the Notice and the Company shall reimburse the Indemnitee for all reasonable expenses related to the action or claim incurred by the Indemnitee prior to the Indemnitee's giving of the Notice.

5. Non−Exclusivity. The rights of Indemnitee hereunder shall be in addition to any rights that Indemnitee may have under the Company's governance documents (e.g. Articles of Incorporation, By−laws, Articles of Organization, Regulations, etc.) (the "Governance Documents"), applicable law or otherwise and shall survive any termination, resignation, death or other dismissal of Indemnitee. No amendment or alteration of the Company's Governance Documents shall adversely affect Indemnitee's rights under the Governance Documents or this Agreement.

6. Insurance. To the extent the Company maintains, at its expense, an insurance policy or policies providing liability insurance with respect to the acts or omissions covered by this Agreement, Indemnitee shall be covered by such policy or policies, in accordance with its or their terms, to the maximum extent of the coverage available there under.

7. Payment. The Company shall not be liable to Indemnitee under this Agreement to make any payment in connection with any claim against Indemnitee to the extent the Indemnitee has otherwise actually received, and is entitled to retain, payment (under any insurance policy or otherwise) of the amounts otherwise indemnifiable hereunder.

8. Enforceability. The indemnification contained in this Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties hereto and their respective successors, assigns (including any direct or indirect successor by purchase, merger, consolidation, liquidation or otherwise to all or substantially all of the business and/or assets of the Company), spouses, heirs and personal and legal representatives.

9. Binding Obligation. If this Agreement or any portion hereof shall be found to be invalid on any ground by any court of competent jurisdiction, then the Company shall nevertheless indemnify and hold harmless Indemnitee, as to costs, charges and expenses (including court costs and attorneys' fees), judgments, fines, penalties and amounts paid in settlement with respect to any action, suit or proceeding, whether civil, criminal, administrative, arbitrative or investigative, and in any appeal in such action, suit or proceeding, and in any inquiry or investigation that could lead to such an action, suit or proceeding, to the full extent permitted by any applicable portion of this Agreement that shall not have been invalidated and to the fullest extent permitted by applicable law.

10. Governing Law; Venue. This Agreement shall be construed in accordance with and governed by the laws of the State of Texas, without regard to the principles of conflicts of laws. The parties agree that any litigation directly or indirectly relating to this Agreement must be brought before and determined by a court of competent jurisdiction within Harris County, Texas, and the parties hereby agree to waive any rights to object to, and hereby agree to submit to, the jurisdiction of such courts.

11. Right to Sue; Attorneys' Fees and Costs. If a claim by Indemnitee for payment of Losses hereunder is not paid in full by the Company within forty−five (45) days after a written claim has been delivered to the Company, Indemnitee may at any time thereafter bring suit against the Company to recover the unpaid amount of the claim. If successful in whole or in part in any such suit, Indemnitee shall be entitled to be paid also the reasonable costs and expenses of prosecuting such suit. In any suit brought by Indemnitee to enforce any right hereunder (including, without limitation, the right to indemnification), the burden of proving that Indemnitee is not entitled to such right shall be borne by the Company. If a claim by the Company for repayment of any Non−Indemnification Losses previously paid on behalf of Indemnitee hereunder is not repaid in full to the Company within forty−five (45) days after such ruling has been delivered to Indemnitee, the Company may at any time thereafter bring suit against the Indemnitee to recover the unpaid amount.

12. Successors and Assigns. This Agreement shall be binding upon and shall inure to the benefit of the heirs, successors and assigns of each party to this Agreement.

13. Amendment. This Agreement may be amended, modified or supplemented only by a written instrument executed by each of the parties hereto.

14. Facsimile and Counterpart Signature. This Agreement may be executed by facsimile signature and in one or more counterparts, each of which shall for all purposes be deemed an original and all of which shall constitute the same instrument, but only one of which need be produced.

IN WITNESS WHEREOF, the undersigned have executed this Agreement as of the date first above written.

COMPANY

W&T OFFSHORE, INC.

By: /s/ Tracy W. Krohn
Name: Tracy W. Krohn
Title: President and CEO

INDEMNITEE

/s/ S. James Nelson, Jr.
S. James Nelson, Jr.

SUBSIDIARIES OF W&T OFFSHORE, INC.

The subsidiaries of W&T Offshore, Inc., all of which are wholly owned, are listed below.

Name	State of Organization
Offshore Energy I LLC	Delaware
Offshore Energy II LLC	Delaware
Offshore Energy III LLC	Delaware
Gulf of Mexico Oil and Gas Properties LLC	Delaware
W&T Energy V, LLC	Delaware
W&T Energy VI, LLC	Delaware
W&T Energy VII, LLC	Delaware
W&T Holdings, L.L.C.*	Louisiana

* W&T Offshore, Inc. has commenced the process of dissolving this subsidiary.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333−126251 and 333−126252 on Form S−8 of our report dated March 30, 2006 relating to the consolidated financial statements of W&T Offshore, Inc. and subsidiaries (the “Company”) that appear in this Annual Report on Form 10−K of the Company for the year ended December 31, 2005.

/s/ ERNST & YOUNG LLP

New Orleans, Louisiana
March 30, 2006

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers and geologists, we consent to the references to our firm in the W&T Offshore, Inc. Annual Report on Form 10−K for the year ended December 31, 2005 and to the incorporation by reference in this Form 10−K to our estimates of reserves and value of reserves, and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2005, 2004 and 2003 included in the W&T Offshore, Inc. Annual Report on Form 10−K for the year ended December 31, 2005. We further consent to the incorporation by reference of information contained in our reports as of December 31, 2005 in the W&T Offshore, Inc. Registration Statement Nos. 333−126251 and 333−126252 on Form S−8.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /S/ FREDERIC D. SEWELL
Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
March 31, 2006

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)) 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) 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

    c) 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 31, 2006

/s/ TRACY W. KROHN
Tracy W. Krohn
Chief Executive Officer, President and Treasurer

Exhibit 31.2

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

I, William W. Talafuse, 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)) 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) 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

    c) 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 31, 2006

/s/ WILLIAM W. TALAFUSE
William W. Talafuse
Senior Vice President, interim Chief Financial Officer and Chief Accounting 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, 2005 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 31, 2006

/s/ Tracy W. Krohn
Tracy W. Krohn
Chief Executive Officer

Date: March 31, 2006

/s/ William W. Talafuse
William W. Talafuse
Senior Vice President, interim Chief Financial Officer and Chief Accounting Officer