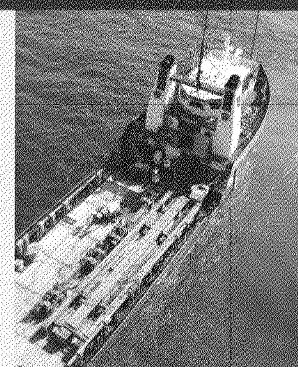
Prepared for Opportunities

W&T Offshore 2008 Annual Report

Flexibility

W&T Offshore adds reserves through exploration AND acquisitions.

W&T is capable of both finding and acquiring oil and gas reserves at attractive prices, enabling the company to seize the best opportunities at the appropriate times. This flexibility gives W&T an advantage that benefits shareholders in up and down markets.



491

PROVED RESERVES (BCFE)

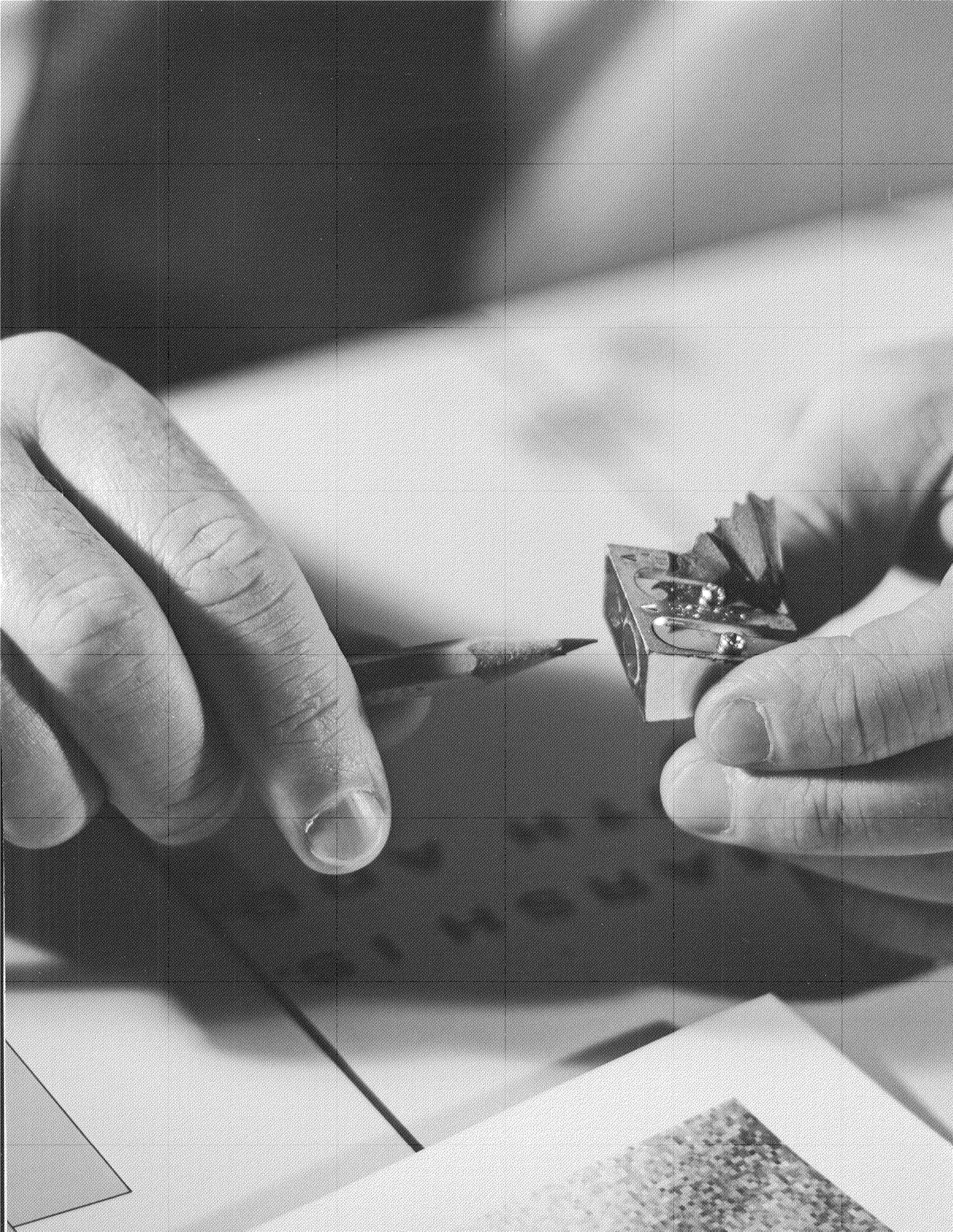
$357

YEAR-END CASH (IN $ MILLIONS)

Financial Discipline

The W&T practice of drilling only within cash flow prepares the company to prosper in times of high and low commodity prices.

Drilling wells with borrowed money poses risks and is more expensive. Using company cash to fund drilling protects W&T when credit is expensive and difficult to obtain. Maintaining high liquidity and low debt are other essential elements of a conservative approach that helps the company secure affordable financing to fund acquisitions.



Focus

W&T's consistent focus on generating positive cash flow and high rates of return rewards shareholders.

Every decision W&T makes – from drilling locations to when and what the company acquires – passes through this filter. The company's decades-long focus on cash flow and high returns is reinforced through large insider ownership and emphasized with one of the lowest G&A expense ratios in the industry.

55

% INSIDER OWNERSHIP

Dear Shareholders:

Fiscal year 2008 underscored the wisdom of being prepared. Despite wild swings in commodity prices and the deteriorating global economy, W&T finished the year with record revenue and adjusted EBITDA and eyes wide open for opportunity in 2009.

In fiscal year 2008, revenue topped $1.2 billion, a 9.1 percent increase over the same period in fiscal year 2007. Adjusted net income for the same period reached $201 million, a 17 percent increase.

We concluded the year with $350 million in cash and an untapped revolving credit line of $500 million.

Given the year's fluctuations in financial and energy markets, quarterly results made W&T look like two different companies. For nine months, high commodity prices helped drive revenues and earnings to record levels. In the final three months, commodity prices - and our revenue - turned south.

Compounding fourth-quarter problems for exploration and production companies were continuing high costs for the goods and services needed to find and produce oil and gas. While oil and gas prices were falling through the floor, our contracted cost for drilling rigs - the big-ticket item we need to succeed - remained at or near the ceiling.

Based on these high costs, equipment delays, falling commodity prices and the lack of qualified contractor personnel, we reduced our capital budget and drilling forecast during the year. It was a prudent decision.

Hurricanes Ike and Gustav also impacted revenues and our ability to add to reserves. Two operated platforms and nine non-operated platforms toppled during the storms, and we also faced production deferrals due to pipeline damage. By the end of the first quarter of 2009, we expect the vast majority of that production to be back on line. However, as much as 8 million cubic feet per day - about 3 percent of our production at year-end - may not resume.

In spite of hurricanes and market turmoil, we achieved a lot during the year. Among the most notable achievements:

- successful completion of 18 of 24 exploration wells, a 75 percent success rate
- successful completion of 2 of 2 development wells
- purchase of the balance of the Ship Shoal 349 field (better known as "Mahogany"), which contains a sizable, deeper prospect

We concluded the year with 491 Bcfe in proved reserves, a 23 percent decline from 2007. That decrease is largely due to the steep year-end decline in oil and gas prices. Regardless, we remain a healthy company with a large portfolio of proved and unproved reserves in the Gulf of Mexico.

Preparation: Flexibility, Financial Discipline and Focus

Turmoil throughout the energy industry and across the world's financial markets and economies has left investors shaken. Everyone needs some encouraging news, and I think we have some for W&T shareholders.

That belief is based on experience and our preparation. Since 1983, the first year we were in business, we've experienced numerous energy market downturns. While we'd much rather see higher than lower commodity prices, we've shown we can prosper in both environments – if we're prepared.

Preparation requires being flexible. Among exploration and production companies, ultimate flexibility comes from having more than one way to expand reserves. W&T has consistently demonstrated the ability to expand reserves by acquiring properties and entire companies, as well as through exploration. In fact, we have one of the best exploration track records in the Gulf of Mexico, and I'd match our history of successful acquisitions against anyone's.

The second aspect of preparation is a conservative financial approach. Many of the companies operating in the Gulf of Mexico theorize about funding their drilling operations from their cash flow. We do it routinely. As a result, we have a financial profile that makes financing for acquisitions easier and less costly to obtain.

At the end of 2008, our liquidity – measured by cash, debt and line of credit – was approximately the same as it was in 2007. That's the result of good preparation and planning for volatile cycles.

The third facet of preparation is focus. Amid the peaks and valleys of commodity prices, we maintain a focus on four things that have produced excellent financial results:

- high cash flow
- high rates of return (historically available with Gulf of Mexico properties)
- market-driven balance between drilling and acquisition
- adding to the acreage we need to succeed

As the company's largest shareholder, I make sure this focus is clearly understood throughout W&T.

2009: Improving Conditions for Acquisitions

Downturns are familiar to W&T. Even in a down economic cycle, our goal remains to increase production and replace reserves. Of course, the key to success in a downturn is to have planned for it, and the most important part of our plan is the ability to fund drilling with our own cash flow.

Another critical factor is the ability to schedule drilling and production to our advantage. More than 79 percent of our properties are held by production. This allows us to focus on properties under primary term and postpone drilling on properties that we'll likely have access to for years to come.

Beyond that, the silver lining in the cloud of falling commodity prices and the economic slowdown is the opportunity to purchase assets - and perhaps entire companies - at attractive prices. Led by Reid Lea, Executive Vice President and Manager of Corporate Development, our acquisition efforts are in high gear.

Some of the opportunities we were presented in 2008 are now being re-presented with more attractive pricing. We expect more opportunities to surface as companies seek to improve their financial strengths. We also expect more companies to seek drilling partners to preserve their liquidity. In both cases, we're prepared to seize the opportunities that make sense.

Rethinking Drilling Budgets and Energy Basins

Typically, by the time you receive this report, we have established a drilling budget for the year. As I write this, the 2009 budget is anticipated to range between $220 and $270 million. That's a strategic decision based on the lag time in the cost of goods and services vs. the price of commodities. For now, it's to our advantage to not overcommit to the year's drilling program and budget, but to see what the environment provides and act accordingly. I believe this budget allows us to do that.

The downturn is also causing us to revisit the economics of different oil and gas basins around the world. W&T has always been capable of drilling on land and in other offshore basins, but the Gulf of Mexico has typically offered higher, more substantial returns. Today's economics may make other basins attractive to consider.

Prepared for What's Next

Since W&T's founding, the length of contractions in energy markets has compressed. We're hopeful that trend will continue, but we can't count on it.

We continue to prepare for the worst and hope for the best. That preparation requires smart, experienced leaders. In 2008, one of our best and brightest, Jamie Vazquez, was promoted from Vice President of Land to W&T President. For the past decade, Jamie has applied a clear focus, methodical problem-solving skills and tremendous expertise in managing our offshore properties. We are a more profitable company because of her efforts.

In fact, W&T has 299 employees who share a common mission of rewarding W&T shareholders. Most of our employees own company stock, reinforcing the importance of our mission. Whatever 2009 brings, you can count on all of us to work diligently on behalf of your interests.

Very truly yours,

Tracy W. Krohn

Tracy W. Krohn, Founder & Chief Executive Officer

Board of Directors & Executive Officers

Board of Directors

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

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

Samir G. Gibara[1,2]
Retired Chairman & CEO of The Goodyear Tire & Rubber Company

Virginia Boulet[3]
Special Counsel Adams & Reese LLP

Robert I. Israel[1]
Partner, Compass Advisers, LLP

S. James Nelson, Jr.[1,2]
Chairman of the Company's Audit Committee, Retired former Vice Chairman of Cal Dive International (Now Helix Energy Solutions)

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

Executive Officers

Tracy W. Krohn
Founder, Chairman & Chief Executive Officer

J. Freel
Founder, Secretary, Director & Chairman Emeritus

Jamie L. Vazquez
President

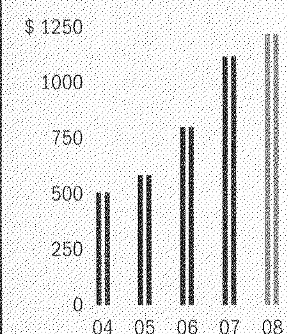
W. Reid Lea
Executive Vice President & Manager of Corporate Development

Steve Schroeder
Senior Vice President & Chief Operating Officer

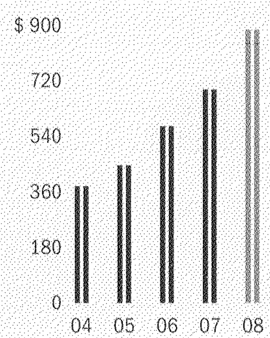
Danny Gibbons
Senior Vice President & Chief Financial Officer

Financial Highlights

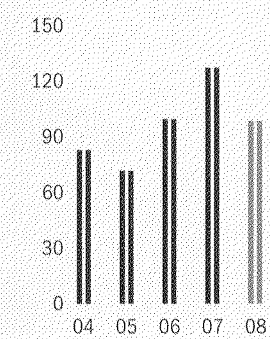
	2008	2007	2006	2005	2004
Income Statement (year ended December 31)					
Total Revenues (in thousands)	$ 1,215,609	$ 1,113,749	$ 800,466	$ 585,136	$ 508,715
Operating Income (Loss)	$ (807,145)	$ 249,249	$ 317,615	$ 288,425	$ 231,332
Net Income (Loss)	$ (558,819)	$ 144,300	$ 199,104	$ 189,023	$ 149,482
Cash-Flow Statement (year ended December 31)					
Operating Activities	$ 882,496	$ 688,597	$ 571,589	$ 444,043	$ 377,275
Capex (oil and gas properties)	$ 774,879	$ 361,235	$ 1,650,747	$ 322,984	$ 282,510
Balance Sheet (as of December 31)					
Total Assets	$ 2,056,186	$ 2,812,204	$ 2,609,685	$ 1,064,250	$ 760,784
Long-Term Debt	$ 653,172	$ 654,764	$ 684,997	$ 40,000	$ 35,000
Shareholders' Equity	$ 572,227	$ 1,151,340	$ 1,042,917	$ 543,383	$ 359,878
Operating Data					
Natural Gas (MMcf)	56.1	76.7	60.4	46.5	53.3
Oil (MBbls)	7.0	8.3	6.5	4.1	4.8
Total Natural Gas and Oil (MMcfe)	97.9	126.5	99.2	71.1	82.4
Average Daily Equivalent Sales (MMcfe/d)	267.5	346.7	271.7	194.7	225.2
Average Realized Sales Price:					
Natural Gas ($/Mcf)	$ 9.40	$ 7.20	$ 7.08	$ 8.27	$ 6.18
Oil ($/Bbl)	$ 98.72	$ 67.58	$ 57.70	$ 48.85	$ 36.77
Estimated Net Proved Reserves					
Natural Gas (Bcf)	227.9	332.8	401.2	215.9	227.6
Oil (MMBbls)	43.9	51.0	55.7	45.9	40.0
Total (Bcfe)	491.1	638.8	735.2	491.5	467.5
Total Proved Developed (Bcfe)	334.1	395.3	478.9	318.6	290.2
Proved Undeveloped (Bcfe)	157.0	243.5	256.3	172.9	177.3
Proved Developed Reserves as a % of Proved Reserves	68.0 %	61.9 %	65.1 %	64.8 %	62.1 %



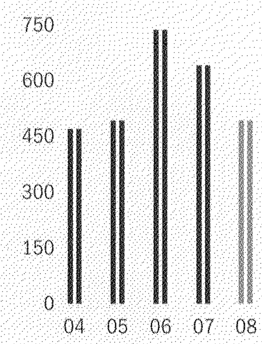
Revenues
(in millions)



Cash Provided from Operating Activities
(in millions)



Production
(Bcfe)



Proved Reserves
(Bcfe)

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

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, 2008

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

SEC Mail Processing Section
APR 17 2009
Washington, DC
101

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

Texas	**72-1121985**
(State of incorporation)	**(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300 Houston, Texas	**77046-0908**
(Address of principal executive offices)	**(Zip Code)**

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

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

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

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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 $1,989,030,775 based on the closing sale price of $58.51 per share as reported by the New York Stock Exchange on June 30, 2008.

The number of shares of the registrant's common stock outstanding on February 20, 2009 was 76,289,286.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, 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 of 1933 and Section 21E of the Securities and Exchange Act of 1934, that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A. "Risk Factors" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" of this Annual Report on Form 10-K and may be discussed or updated from time to time in subsequent reports filed with the Securities and Exchange Commission. 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," "our" and the "Company" refer to W&T Offshore, Inc. and its consolidated subsidiaries.

PART I

Item 1. *Business*

W&T Offshore, Inc. is a Texas corporation originally organized as a Nevada corporation in 1988, and successor by merger to W&T Oil Properties, Inc., a Louisiana corporation organized in 1983. We are an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties in the Gulf of Mexico, where we have developed significant technical expertise and where high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid return on our invested capital. We have leveraged our historic experience in the conventional shelf (water depths of less than 500 feet) to develop higher impact capital projects in the Gulf of Mexico in both the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet and water depths of less than 500 feet). We have acquired rights to develop and exploit new prospects and acquired existing oil and natural gas properties in both the deepwater and the deep shelf, while at the same time continuing our focus on the conventional shelf. We have interests in leases covering approximately 1.4 million gross acres (0.8 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. Approximately 79% of our total gross acreage is held-by-production.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultant, our total proved reserves at December 31, 2008 were 491.1 Bcfe. We calculate that our total proved reserves had a present value of estimated future net revenues discounted at 10% ("PV-10"), after considering future cash outflows related to asset retirement obligations and without deducting any future income taxes, of approximately $930.9 million and a standardized measure of discounted future cash flows of approximately $761.7 million as of December 31, 2008. Approximately 68% of our reserves were classified as proved developed (of which 38% were classified as non-producing) and 32% were classified as proved undeveloped. Classified by product, 46% of our reserves were natural gas and 54% were oil and natural gas liquids. For additional information about our proved reserves, see Item 2. "*Properties – Proved Reserves*."

We seek to increase our reserves through acquisitions and drilling programs. We have focused on acquiring properties where we can develop an inventory of drilling prospects that will enable us to add reserves post-acquisition. Our acquisition team continues to work diligently to find properties that fit our profile and that we believe will add strategic and financial value to our company.

On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger for approximately $1.1 billion. The properties acquired included interests in approximately 100 fields on 242 offshore blocks spreading across the Western, Central and Eastern U.S. Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, bank financing and proceeds from a public offering of our common stock.

On December 21, 2007, we entered into an agreement with Apache Corporation ("Apache") to acquire its interest in Ship Shoal 349 field for $116.6 million in cash. This field is located off the coast of Louisiana and covers two federal offshore lease blocks, Ship Shoal blocks 349 and 359. The transaction closed on January 29, 2008, with an effective date of January 1, 2008. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and gas reserves acquired were 60.5 Bcfe. This acquisition was funded from cash on hand. For additional details about this transaction, refer to Note 4 to our consolidated financial statements.

For the year ended December 31, 2008, capital expenditures for oil and gas properties of $774.9 million included $116.6 million for the acquisition of Apache's interest in Ship Shoal 349 field, $337.6 million for exploration activities, $265.3 for development activities and $55.4 million for seismic, capitalized interest and other leasehold costs. We participated in the drilling of 24 exploratory wells and two development wells of which 21 were on the conventional shelf and five were on the deep shelf. Both of the development wells were successful and 18 of the exploratory wells were successful. We operate 12 of the 18 successful exploratory wells.

During the three-year period ended December 31, 2008, we participated in the drilling of 57 exploratory wells, of which 43 were successful (which we define as completed or planned for completion). For a more detailed discussion of our drilling activity and capital expenditures, see Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital expenditures.*"

We participated in bidding for Gulf of Mexico leases on the outer continental shelf ("OCS") at the March 2008 OCS Lease Sale 206 conducted by the U.S. government through the Minerals Management Service ("MMS"). The MMS awarded us leases covering four OCS blocks located on the conventional shelf in the central Gulf of Mexico for a total lease bonus of approximately $3.3 million. We also participated in OCS Lease Sale 207 in August 2008 and we were awarded one lease for a lease bonus of approximately $2.5 million.

During the second half of 2008, oil and natural gas prices fell from record high levels. The declines in oil and natural gas prices coincided with a significant deterioration in the financial markets and the economy in general. As a result of continued economic uncertainty, our drilling activity and capital expenditures in 2009 will be less than our drilling activity and capital expenditures in 2008. Our capital expenditure budget for 2009 is expected to approximate $220 million to $270 million and includes estimates for the completion of wells that were in progress at the end of 2008, wells or projects that we are presently committed to, lease saving operations, development wells where the rig is on location, scheduled recompletions and the development of our Green Canyon Block 646 prospect ("Daniel Boone"). We anticipate fully funding our 2009 capital expenditures with internally generated cash flow and cash on hand. Our capital expenditure budget does not include any amounts for potential acquisitions.

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. Because of ongoing market turmoil, we also believe that other less well-capitalized producers may seek buyers for their properties, which could create opportunities for us.

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

We believe our financial approach has contributed to our success and has positioned us to capitalize on new opportunities. Historically, we have limited our annual capital spending for exploration, exploitation and development activities to net cash provided by operating activities and we have used capacity under our credit agreement for acquisitions and to balance working capital fluctuations. In 2009, we expect to fund our capital expenditures with internally generated cash flow and cash on hand.

Competition

The oil and natural gas industry is highly competitive. We are currently focused almost exclusively 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 domestic and foreign 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. 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. Because of the deterioration of the capital markets, especially for companies with similar credit profiles, acquiring properties and funding exploration and development activities has become significantly more challenging. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see Item 1A. "*Risk Factors.*"

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil and natural gas through third-party marketing companies. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2008 we sold over 10% of our production to each of Shell Trading and Chevron. See "*Concentration of Credit Risk*" in Note 1 to our consolidated financial statements for additional information about our sales to these customers. Due to the nature of oil and natural gas markets and because oil and natural gas are freely traded commodities and there are numerous purchasers in the Gulf of Mexico, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production.

Regulation

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

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

Similarly, the natural gas pipeline industry may also be subject to state regulations which may change from time to time. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 ("Competition Bill") and H.B. 1920 ("LUG Bill"). The Competition Bill gives the Railroad Commission of Texas ("RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007.

The Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the MMS and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers working in the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. On June 18, 2008, the MMS issued a final rule, effective August 18, 2008, that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the NGA to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as W&T, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as W&T, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected any differently than other producers of natural gas.

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. As a result, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

While the changes by these federal and state regulators for the most part affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC, MMS or state regulators will take on these matters; however, we do not believe that any such action taken will affect us differently, in any material way, than other natural gas producers with which we compete.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are transacted 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.

As it relates to intrastate crude oil, condensate and natural gas liquids pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

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

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

Federal leases. Most of our operations are conducted on federal oil and natural gas leases, which are administered by the MMS pursuant to the OCSLA. These leases are awarded based on 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. These plans must include certain information on the potential environmental impacts of the lessee's proposed activities, including waste and air emissions projected to be generated by the activities, proposed environmental monitoring activities, and potential impacts on marine mammals and endangered and threatened species. 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 operations. The MMS has promulgated regulations requiring offshore production facilities, structures and producer-operated pipelines located on the OCS to meet stringent engineering, construction and safety specifications. The MMS also restricts the flaring or venting of natural gas and prohibits the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines.

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 is determined based on the New York Mercantile Exchange prices adjusted for locality and quality differentials. MMS regulations also govern the treatment of operations carried out under joint operating agreements.

Environmental regulations. We are subject to stringent federal, state and local environmental laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and producing operations, the amounts and types of materials that may be released into the environment, the discharge and disposal 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 costs 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 are significant costs to us. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

The effects of Hurricanes Ivan, Katrina and Rita during the 2004 and 2005 hurricane seasons, and Hurricanes Ike and Gustav in 2008, significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The MMS continues to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the MMS has periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. Recommended practices for the use of moored rigs during hurricane season were issued in 2006 in a Notice to Lessees ("NTL") to ensure that consistent proper site assessments are performed and minimum design return periods are established across the Gulf of Mexico in an effort to decrease the number of moored rig failures during hurricanes. Additional operational enhancements were implemented by the MMS during the 2007 and 2008 hurricane seasons. In 2007, an NTL provided further guidance to insure that the design of new OCS platforms and related structures fully considers specific environmental conditions at the platform location in compliance with the requirements of 30 CFR 250.900(a). An NTL issued in 2008 also provided guidance to insure the fitness of any jack-up drilling rig that may be used to conduct operations during hurricane season. It is possible that similar, if not more stringent, requirements will be issued by the MMS for the 2009 hurricane season. These new requirements could increase our operating costs.

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 oil or a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons are subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations, prepare an inventory of greenhouse gas emissions resulting from our operations, or pay a tax on the greenhouse gas emissions resulting from our operations. These requirements could increase our operational and compliance costs and result in reduced demand for the oil and natural gas we produce.

Also, as a result of the United States Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. Environmental Protection Agency* ("EPA"), the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal CAA's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, the EPA released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of greenhouse gas emissions under the CAA, in response to the Supreme Court's decision in *Massachusetts*. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the CAA and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on our business and the demand for the oil and natural gas we produce.

The Federal Water Pollution Control Act of 1972, as amended, (the "Clean Water Act") imposes restrictions and controls on the discharge of oil, 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 ("NPDES") 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. In October 2007, the EPA issued a new general NPDES permit applicable to discharges from oil and gas exploration and production activities in the Western Gulf of Mexico. This revised permit contains a requirement to contain maintenance waste such as removed paint and materials associated with surface preparation and coating applications to "the maximum extent practicable to prevent discharge," which includes a requirement to contain airborne materials such as spent or oversprayed abrasives, paint chips, and paint overspray. The permit also requires that certain recommended practices for containing waste be implemented prior to conducting sandblasting or similar maintenance activities. 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, the Oil Pollution Act of 1990 ("OPA90") 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, OPA90, 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, established 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 less than five permitted underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

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

Federal Lease Stipulations address the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The MMS also issues numerous NTL's that provide formal guidelines on implementation of OCS regulations and standards. Recent NTL's prescribing measures to minimize threats to protected marine species with which we must comply include 2007-G02 *Implementation of Seismic Survey Mitigation Measures and Protected Species Observer Program*, 2007-G03 *Marine Trash and Debris Awareness and Elimination*, 2007-GO4 *Vessel Strike Avoidance and Injured/Dead Protected Species Reporting*, and 2004-G06 *Structure Removal Operations*, among others. MMS conditions permit approvals on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases.

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

Our oil and natural gas operations include a production platform in the Gulf of Mexico located in a National Marine Sanctuary. As a result, we are subject to additional federal regulation, including by the National Oceanic and Atmospheric Administration. Unique regulations related to operations in a sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Emergency Planning and Community Right-to-Know Act, the Endangered Species Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Magnuson-Stevens 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, may require certain mitigation measures to avoid harm to wildlife, and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities.

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

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

We maintain insurance covering well control, property and hurricane damage, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain does 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 such risks or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant environmental 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, 2008, we employed 299 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, or furnished to, the SEC. This Annual Report and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Nine Greenway Plaza, Suite 300, Houston, Texas 77046 or by calling (713) 297-8024. These reports are also available at the SEC Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The public may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and information 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

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. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion ($768.8 million after-tax). The further declines in oil and natural gas prices after December 31, 2008 may require us to record an additional ceiling test impairment in 2009. No assurance can be given that we will not experience a ceiling test impairment in future periods, which could have a material adverse effect on our results of operations in the period taken. As a result of lower oil and natural gas prices, we may also reduce our estimates of the reserves that may be economically recovered, which could reduce the total value of our proved 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*" and Note 1 to our consolidated financial statements for a discussion of the ceiling test.

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 directly affects our revenues, 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 and will likely continue to be volatile in the future. The prices we receive for our production and the volume 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 ("OPEC");
- the price and quantity of imports of foreign oil, natural gas and liquefied natural gas;
- acts of war or terrorism;
- economic conditions;
- 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. The prices of oil and natural gas declined substantially during the second half of 2008 and have continued to decline thus far in 2009. A continued environment of depressed oil and natural gas prices, or a continued decline in such prices, would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We have been and are currently being adversely affected by a recession in the United States and global economy.

The current recessionary economic environment has resulted in lower demand for oil and natural gas and less capital available to fund our growth. Should such conditions continue or worsen, these factors would negatively impact our profitability and/or limit our growth.

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

Borrowings under the revolving portion of our Third Amended and Restated Credit Agreement, as amended (the "Credit Agreement"), are currently limited to $500.0 million. Availability is determined periodically at the discretion of the lenders and is based in part on oil and natural gas prices and in part on our proved reserves. Substantially all of our oil and gas properties are pledged as collateral under the Credit Agreement. The Credit Agreement limits our ability to incur additional indebtedness based on specified financial covenants, ratios or other criteria. Lower oil and natural gas prices in the future could result in a reduction in availability and also affect our ability to satisfy these covenants, ratios or other criteria and thus could reduce our ability to incur additional indebtedness. Lower oil and natural gas prices, over a sustained period of time and without a corresponding decline in the cost of goods and services necessary to conduct our operations, could affect our ability to replace reserves and thus could reduce our ability to incur additional indebtedness.

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

We could be exposed to uninsured losses in the future. The occurrence of a significant accident or other event not covered in whole or in part by our insurance could have a material adverse impact on our financial condition and operations. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. 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. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. We are also exposed to the possibility that we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim.

During the year ended December 31, 2008, we spent approximately $17.7 million to remediate damage related to Hurricanes Ike and Gustav that was either not covered by insurance or has yet to be recovered from our insurance underwriters. During the years ended December 31, 2007 and 2006, we spent approximately $18.5 million and $0.5 million, respectively, to remediate hurricane damage that was not covered by insurance, all of which related to Hurricanes Katrina and Rita in 2005.

Insurance for well control and hurricane damage may become significantly more expensive for more limited coverage and some losses currently covered by insurance may not be covered in the future.

Due to increased loss experience in recent years with hurricanes in the Gulf of Mexico and the current turmoil in the financial markets, property damage and well control insurance coverage has become more limited and the cost of coverage has increased. In June 2008, we renewed our insurance policy covering well control and hurricane damage at a cost of approximately $25.5 million. The current policy limits for well control and hurricane damage are $100 million and $150 million, respectively, with an additional $100 million for well control and hurricane damage on our Ship Shoal 349 field. We also have an insurance policy with a limit of $250 million that provides coverage for removal of wreckage if mandated by any governmental authority as a result of a named windstorm. Our insurers may not continue to offer this type and level of coverage to us, or our costs may increase substantially as a result of increased premiums and the increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we may periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. For example, in January 2006 we entered into commodity swap and option contracts (as required by our credit agreement) relating to approximately 14 Bcfe, or 14%, of our production in 2006, 18 Bcfe, or 14%, of our production in 2007 and 11 Bcfe, or 11%, of our production in 2008 in connection with the anticipated financing related to the acquisition of oil and natural gas properties from Kerr-McGee. While hedging transactions are intended to reduce the effects of volatile oil and natural gas prices, they may also limit our potential gains if oil and natural gas prices were to increase substantially over the price established by the contracts. 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 points assumed in the hedge arrangements; or
- the counterparty to the hedge contracts fails to perform under the terms of the contracts.

As of December 31, 2008, we did not have any open commodity derivative positions.

As of December 31, 2008, approximately 32% of our total proved reserves were undeveloped and approximately 38% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. We are not the operator with respect to approximately 18% of our proved undeveloped and approximately 27% of our proved developed 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 developed non-producing reserves will ultimately be produced during 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, production and cash flows 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 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, 52% of our total proved reserves are depleted within three years. As a result, our need to replace reserves from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a portion of their reserves outside the Gulf of Mexico area. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow production at the same rates as we have in the past. In addition, due to the significant time requirements involved with exploration and development activities, particularly for wells in the deepwater or wells not located near existing infrastructure, actual oil and natural gas production from new wells may not occur, if at all, for a considerable period of time following the commencement of any particular project.

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 and acquisitions through a combination of cash flow from operations, bank financing and securities offerings. In order to finance future capital expenditures, we may need to alter or increase our capitalization substantially through the issuance of additional 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, the prices of oil and natural gas, and our success in developing and producing new reserves. We anticipate fully funding our 2009 capital expenditures with internally generated cash flow and cash on hand. Our capital expenditure budget does not include any amounts for potential acquisitions. Planned reductions in our capital expenditures to stay within internally generated cash flow (which have been adversely affected by declining commodity prices) and cash on hand will make replacing produced reserves more difficult. If our cash flow from operations and cash on hand are not sufficient to fund our capital expenditure budget, we may not be able to access additional debt, equity or other methods of financing on an economic or timely basis to meet our 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 natural 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 could require significant capital expenditures and successful drilling operations. Our future oil and natural gas reserves, production and, therefore our cash flow and net 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 may 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 have financial resources that allow them to obtain substantially greater technical expertise and personnel than we have. We actively compete with other companies in our industry when acquiring new leases or oil and natural gas properties. For example, new leases acquired from the MMS are acquired through a "sealed bid" process and are generally awarded to the highest bidder. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we compete with other companies in our industry for such properties 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 drilling activity due, in part, to their geological complexity, depth and higher cost to drill and ultimately develop. 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 costs 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, the drilling of deepwater wells requires specific types of rigs with significantly higher day rates and limited availability, as compared to the rigs used in shallower water. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than development costs for wells drilled on the conventional shelf because deepwater drilling requires larger 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 because deep shelf development requires more drilling days and higher drilling and service costs due to extreme pressure and temperatures associated with greater 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.

Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant since our operations are almost exclusively in the Gulf of Mexico.

We are required to record a liability for the discounted present value of our asset retirement obligations to remove our platforms, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site clean up. These costs are typically considerably more expensive for offshore operations as compared to most land based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations are many years in the future, regulatory requirements may change and asset removal technologies and costs are constantly changing. In 2007 and 2008, we increased our estimates of future asset retirement obligations as a result of our evaluation of increased costs incurred for plugging and abandonment activities in the Gulf of Mexico. We may continue to make significant increases to our asset retirement obligations in future years.

Because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled. Accordingly, our estimate of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

We may not be in a position to control the timing of development efforts, associated costs or the rate of production of the reserves from our non-operated properties.

As we carry out our drilling program, we will not serve as operator of all planned wells. We have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners and our limited ability to influence operations and associated costs of properties operated by others could prevent the realization of our targeted returns on capital in drilling or acquisition activities. 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 assure 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 hinder our efforts to replace reserves.

Our business involves a variety of operating risks, including:

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

Offshore operations are also subject to a variety of operating risks related 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 funds available for exploration, exploitation and acquisitions or result in the loss of property and equipment.

The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenues 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 2008, net production of approximately 21.7 Bcfe was deferred as a result of damage caused by Hurricane Ike and, to a lesser extent, by Hurricane Gustav. In 2006, our net production was deferred by approximately 7.8 Bcfe because of the carryover effect of Hurricanes Katrina and Rita that occurred in 2005.

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

Our business strategy includes a continuing acquisition program. Our recent growth is due in part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. 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;
- estimates of the costs and timing of plugging and abandonment; and
- 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 associated with such risks. 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 natural gas properties or businesses.

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

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

- additional costs due to increased scope and complexity of our operations; and
- potential disruption of our ongoing business.

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

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 proved 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 our reserves at December 31, 2008. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and natural gas reserve quantities*" for a discussion of the estimates and assumptions about our estimated oil and natural gas reserves information reported in Item 1. "*Business*" and Item 2. "*Properties*."

In order to prepare our year-end reserve estimates, our independent petroleum consultant projected our 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 under our control. The process also requires economic assumptions about matters such as oil and natural gas prices, 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.

Prospects that we decide to drill may not yield oil or natural gas in commercial 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 economic quantities 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 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 and completion costs 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 accurately predict the characteristics and potential reserves associated with our drilling prospects. To the extent we drill additional wells in the deepwater and/or on the deep shelf, our drilling activities could 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 commercial 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 our investments.

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 substantially 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 because of a reduction in demand for our production 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 September 2008, as a result of Hurricane Ike, two of our operated platforms and eight non-operated platforms were toppled and a number of platforms, third-party pipelines and processing facilities upon which we depend to deliver our production to the marketplace were damaged.

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

Currently, a portion of our oil and natural gas is processed for sale on platforms owned by parties with no economic interest in our wells and no other processing facilities would be available to process such oil and natural gas without significant investment by us. As of December 31, 2008, five fields, accounting for 28 Bcfe (or 5.7%) of our total proved reserves, are tied back or are planned to be tied back to separate, third-party owned platforms. During September 2008, Hurricane Ike damaged or destroyed a number of oil and natural gas producing platforms in the Gulf of Mexico. Some of these platforms are host to our production and we expect some will be repaired or rebuilt while others will not. There can be no assurance that the owners of such platforms will continue to process our oil and natural gas production. If any of these platform operators ceases to operate their processing equipment, we may be required to shut in the associated wells.

If third party pipelines connected to our facilities become partially or fully unavailable to transport our natural gas or oil, our revenues could be adversely affected.

We depend upon third party pipelines that provide delivery options from our facilities. Because we do not own or operate these pipelines, their continued operation is not within our control. If any of these third party pipelines become partially or fully unavailable to transport natural gas and oil, or if the gas quality specification for the natural gas pipelines changes so as to restrict our ability to transport natural gas on those pipelines, our revenues could be adversely affected. In 2008, net production of approximately 21.7 Bcfe was deferred as a result of damage caused by Hurricane Ike and, to a lesser extent, by Hurricane Gustav.

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, development, production and transportation of oil and natural gas and operational safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with such legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

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

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

- personal injuries;
- property and natural resource damages;
- well reclamation costs; 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 exploration or drilling activities on certain lands lying within wilderness, wetlands and other protected areas or that may affect certain wildlife, including marine mammals; 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.

In the past, we have 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 attain 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 and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages. See Item 1. "*Business – Regulation*" for a more detailed description of our environmental risks.

We operate a production platform in a National Marine Sanctuary.

Our oil and natural gas operations include a production platform located in a National Marine Sanctuary in the Gulf of Mexico that is subject to special federal laws and regulations. Unique regulations related to operations in the Sanctuary include, among other things, prohibition of drilling activities within certain protected areas, restrictions on substances that may be discharged, depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief, including cessation of production from wells associated with this platform. As of December 31, 2008, fields associated with this platform had proved reserves of approximately 2.0 Bcfe, representing less than one percent of our total proved reserves.

The loss of members of our senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Founder, Chairman and Chief Executive Officer; Jamie L. Vazquez, our President; W. Reid Lea, our Executive Vice President and Manager of Corporate Development; John D. Gibbons, our Senior Vice President, Chief Financial Officer and Chief Accounting Officer and Stephen L. Schroeder, our Senior Vice President and Chief Operating 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 certain members of our management team.

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

The offshore oil and gas industry may experience significant shortages in the availability of certain drilling rigs as well as significant increases in the cost of utilizing drilling rigs. This could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition or results of operations. If the unavailability or high cost of rigs, equipment, supplies or personnel were particularly severe in the offshore waters of Texas, Louisiana, Alabama or other parts of the Gulf of Mexico, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

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. We also conduct operations with other energy companies and make joint interest billings to such parties who we also believe represent reasonable credit risk. In some cases, we have required purchasers and joint interest partners to post letters of credit or provide other means of credit support to secure their performance under applicable contracts.

Risks Related to Financings

Recent changes in the financial and credit markets could negatively impact our economic growth. In addition, the recent declines of oil and natural gas prices can affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our current credit facility. These impacts may hinder or prevent us from meeting our future capital needs and may restrict or limit our ability to increase reserves of oil and natural gas.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have become exceedingly distressed. These issues, along with significant asset write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions, have made, and will likely continue to make, it difficult to obtain debt or equity capital funding.

In addition, we may be unable to obtain adequate funding under our current credit facility because (i) our lending counterparties may be unwilling or unable to meet their funding obligations or (ii) our borrowing base under our current revolving credit facility is decreased as the result of a re-determination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason.

Due to these factors, we cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our exploratory and development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Regardless of our currently outstanding debt, substantial acquisitions and exploitation activities could require additional 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 additional 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 2007 we issued $450 million of 8.25% senior unsecured notes (the "Notes") subject to the terms of an indenture and amended the Credit Agreement to provide for an increase in the capacity available under our revolving loan facility to $500.0 million from $300.0 million. See Note 6 to our consolidated financial statements for additional details about these events.

On July 24, 2008, we amended the Credit Agreement to extend the maturity of our revolving loan facility under the Credit Agreement to July 23, 2012 and increase the interest margin by 0.125% across the entire pricing grid for borrowings under the revolving loan facility. Certain other amendments were made to the Credit Agreement which changed or eliminated various covenants, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year.

Effective December 18, 2008, we amended the Credit Agreement further to allow us to repurchase up to $100.0 million (over the life of the Credit Agreement) of our common stock and/or Notes in any allocation that we deem appropriate. No repurchases of either common stock or the Notes has occurred since the date of the amendment, as the Company currently does not have a stock or debt repurchase program in place. The December 18, 2008 amendment does not limit the dividend or share repurchase availability that was changed in connection with the amendment to the Credit Agreement on July 24, 2008. As consideration for the amendment we agreed to an increase in the interest margin by 0.25% across the entire pricing grid for borrowings under the revolving loan facility.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. In addition, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or initiatives by our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, financial condition and results of operations.

Our debt obligations could have important consequences. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future working capital requirements and capital expenditures, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets;
- limit our opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt obligations or to comply with any restrictive terms of our debt obligations;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impair our ability to obtain additional financing in the future; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

In addition, if we fail to comply with the covenants or other terms of any agreements governing our debt, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral, if any, securing that debt. Realization of any of these factors could adversely affect our financial condition, results of operations and cash flows.

Risks Related to Our Principal Shareholder, Tracy W. Krohn

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

Tracy W. Krohn controls 39,234,187 shares of our common stock, representing approximately 51.4% of our voting interests as of February 20, 2009. As a result, Mr. Krohn has the ability to control the outcome of virtually all matters requiring shareholder approval and other investors, by themselves, will not be able to affect the outcome of virtually any shareholder vote. As a result, Mr. Krohn, subject to any duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

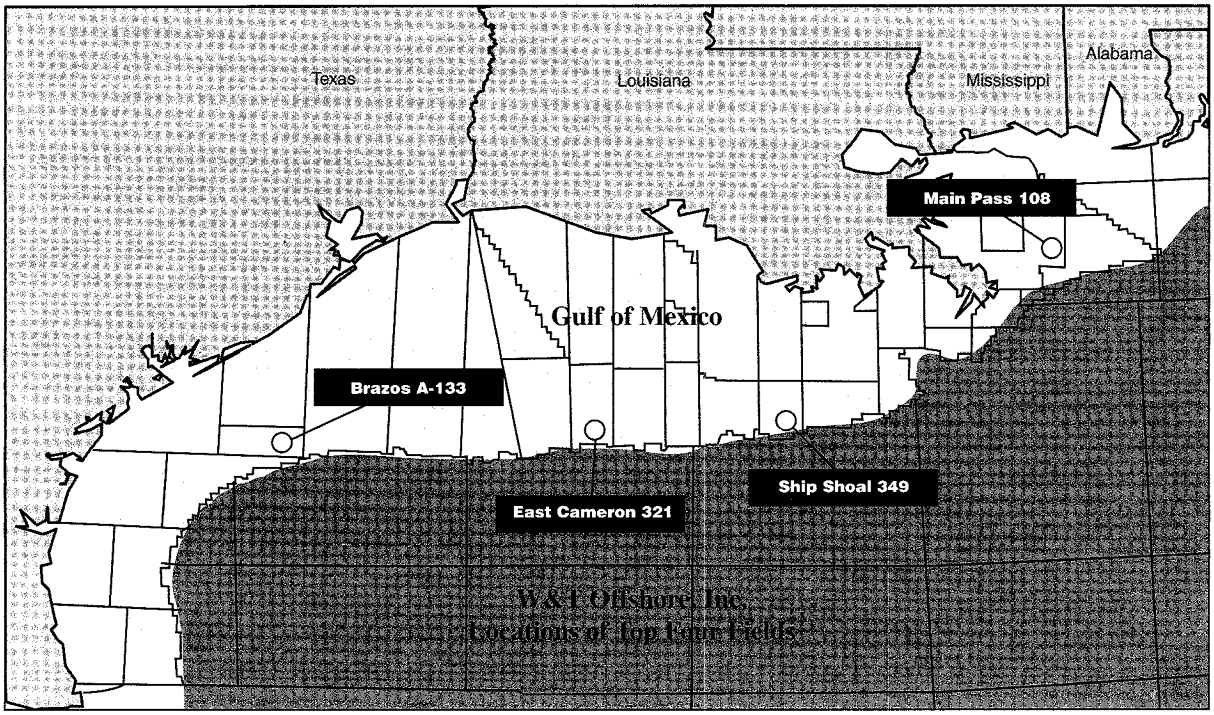
- the composition of our board of directors and, through it, any determination with respect to our business direction and policies, including the appointment and removal of officers;
- the determination of incentive compensation, which may affect our ability to retain key employees;
- any determinations 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; and
- amendments to our amended and restated articles of incorporation or bylaws.

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.

Mr. Krohn owns a majority of our common stock, and therefore 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. We believe, however, that it is in our best interest to have a compensation committee consisting entirely of independent directors. As such, our Compensation Committee Charter adopted by the Board of Directors requires all members to be independent. 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*

None.



Substantially all of our fields are located 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 (based on PV-10 values) as of December 31, 2008. At December 31, 2008, these fields accounted for approximately 61% of our PV-10 value, or $835 million (before estimated asset retirement obligations), and had proved reserves totaling 295 Bcfe.

Field Name	Field Category	Operator	Percent Natural Gas of Net Reserves	2008 Average Daily Equivalent Sales Rate (MMcfe/d) Gross	Net
Ship Shoal 349	Shelf	W&T	18%	15.2	12.7
Main Pass 108	Shelf	W&T	77%	22.5	13.2
Brazos A-133	Shelf	Apache	99%	40.9	8.5
East Cameron 321	Shelf	W&T	46%	24.7	20.6
Green Canyon 19	Deepwater	ExxonMobil	11%	9.8	2.0
High Island 24L	Shelf	Walter	91%	63.5	12.2
Mobile 823	Deep shelf	ExxonMobil	85%	26.6	7.6
Ship Shoal 299	Shelf	W&T	17%	14.3	8.8
South Timbalier 228	Shelf	W&T	11%	7.1	5.9
West Delta 30	Shelf	W&T and Anglo-Suisse (1)	7%	4.4	3.7

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

On December 31, 2008 we had four fields of major significance (having a PV-10 value that individually approximates or exceeds five percent of our total PV-10 value). These fields were Ship Shoal 349, Main Pass 108, Brazos A-133 and East Cameron 321. Listed below are descriptions of those properties, all of which are located on the conventional shelf. The PV-10 values referred to below do not give consideration to estimated asset retirement obligations.

Ship Shoal 349 Field. Ship Shoal 349 field is located off the coast of Louisiana, approximately 235 miles southeast of New Orleans, in 375 feet of water. The field area covers Ship Shoal blocks 349 and 359, with a single production platform on Ship Shoal block 349. Phillips Petroleum discovered the field in 1993. We initially acquired a 25% working interest in the field from BP in 1999. In 2003, we acquired an additional 34% working interest through a transaction with ConocoPhillips that increased our working interest to approximately 59% and we took over as operator in December 2004. In early 2008 we acquired the remaining working interest and we now own a 100% working interest in this field. Cumulative field production through 2008 is approximately 162 Bcfe gross. This field is a sub-salt development with five productive horizons below salt at depths ranging to 17,000 feet. We are currently drilling a well targeting both development and exploration objectives. As of December 31, 2008, 21 wells have been drilled, of which 12 have been successful. Ship Shoal 349 is our largest field in terms of reserves and accounted for approximately 20% of our total PV-10 value of proved reserves at December 31, 2008. Total proved reserves associated with our interest in this field were 133 Bcfe at December 31, 2008. During December 2008, production from this field, net to our interest, averaged 3.6 MMcf of natural gas per day and 1,826 Bbls of oil per day, or 14.6 MMcfe per day.

Main Pass 108 Field. Main Pass 108 field contains six separate OCS blocks, located off the coast of Louisiana approximately 50 miles east of Venice in 50 feet of water. This field includes Main Pass blocks 94, 102, 106, 107, 108 and 109. We acquired our working interests in these blocks, which range from 33% to 100%, in the Kerr-McGee merger transaction. The field produces from a number of low relief, predominantly stratigraphically trapped sands. The productive interval ranges in age from Upper Miocene Big A through Middle Miocene Big Hum. As of December 31, 2008, 49 wells have been drilled in this field, of which 35 were productive. Cumulative field production through 2008 is approximately 313 Bcfe gross. As of December 31, 2008, Main Pass 108 accounted for approximately 8% of our total PV-10 value and total proved reserves associated with our interest in this field were 33 Bcfe. During December 2008, production from this field, net to our interest, averaged 16.2 MMcf of natural gas per day and 357 Bbls of oil per day, or 18.4 MMcfe per day.

Brazos A-133 Field. Brazos A-133 field is located 85 miles east of Corpus Christi, Texas in 200 feet of water. The field was discovered in 1978 by Cities Service Oil Company with production commencing in 1978. There are five active platforms, three of which are production platforms. Cumulative field production through 2008 is approximately 821 Bcfe gross from the Middle Miocene Tex W and Big Hum sections. The bulk of the production is from the Big Hum CM-7 sand, which is a 4-way closure downthrown to the Corsair Fault and bisected by antithetic faults. The top of the CM-7 sand is at a subsea depth of 12,000 feet. Since its discovery, 22 wells have been drilled with 17 being completed as producers. We own a 25% working interest that was obtained through the Kerr-McGee merger transaction. As of December 31, 2008, Brazos A-133 accounted for approximately 5% of our total PV-10 value and total proved reserves associated with our interest in this field were 28 Bcfe. During December 2008, production from this field, net to our interest, averaged 7.6 MMcf of natural gas per day and 15 Bbls of oil per day, or 7.7 MMcfe per day.

East Cameron 321 Field. East Cameron 321 field is located approximately 97 miles off the Louisiana coastline in 225 feet of water. Two production facilities, the "A" and "B" platforms, are located on the block. This field has multiple sands that are productive in faulted, structural traps. As of December 31, 2008, 75 wells have been drilled of which 57 have been successful. Cumulative field production through 2008 is approximately 538 Bcfe gross. We own a 100% working interest in the field and are the operator of the field. As of December 31, 2008, East Cameron 321 accounted for approximately 5% of our total PV-10 value and total proved reserves associated with our interest in this field were 16 Bcfe. Production from this field is currently restricted to dry gas only as a result of damage to a third-party oil pipeline system caused by Hurricanes Gustav and Ike in 2008. During December 2008, net production averaged 5.2 MMcf of natural gas per day. During July 2008 (prior to Hurricanes Gustav and Ike), production from this field, net to our interest, averaged 12.5 MMcf of natural gas per day and 2,701 Bbls of oil per day, or 28.7 MMcfe per day. We began restoring production in the first quarter of 2009 and we anticipate production will be fully restored by the end of the first quarter of 2009.

The following is a description of the remainder of our top ten properties, of which four are located on the conventional shelf, one is located in the deepwater and one is located on the deep shelf. We do not believe that individually any of these properties are of major significance (each has a PV-10 value that is less than five percent of our total PV-10 value, excluding consideration of estimated asset retirement obligations).

Green Canyon 19 Field. Green Canyon 19 field is located off the coast of Louisiana, approximately 150 miles southwest of New Orleans in 750 feet of water. This field covers Green Canyon block 18 and wells drilled from the A-platform located in Green Canyon 18 to Ewing Bank block 988. Mobil Oil Corporation discovered the field in 1982, and ExxonMobil Corporation currently operates the field. We initially acquired a 15% working interest in the field from Burlington Resources in 2002. Our working interest was increased through subsequent transactions with Kerr-McGee and BHP Billiton Petroleum Americas to the current level of approximately 25%. The field produces from multiple Pleistocene and Pliocene sands on the flank of a salt structure. Traps are both structural and stratigraphic. As of December 31, 2008, 59 wells have been drilled of which 47 have been successful. Cumulative field production through 2008 is approximately 648 Bcfe gross. In December 2008, production from this field was shut-in due to Hurricanes Gustav and Ike. During July 2008 (prior to Hurricanes Gustav and Ike), production from this field, net to our interest, averaged 0.6 MMcf of natural gas per day and 436 Bbls of oil per day, or 3.2 MMcfe per day. In the first quarter of 2009, the operator restored oil production at a restricted rate and such restricted rate will continue until the third party gas sales outlet becomes operational. The operator has not indicated a timeframe for the restoration of gas production.

High Island 24-L Field. The High Island Block 24-L field is located 50 miles southeast of Houston, Texas in 42 feet of water. The field was discovered in September 2006 by Walter Oil & Gas Corporation with production commencing in October 2007. Cumulative field production through 2008 is approximately 23 Bcfe from two wells in the Lower Miocene Lentic Jeff section. The structure is a monoclinal south dip within an enclosed fault block trapping thick Lentic Jeff sands downthrown to a large east-west trending expansion fault. The top of the structure is at a subsea depth of 13,638 feet proving a gas column of at least 925 feet. We own a 25% working interest in this field. During December 2008, production from this field, net to our interest, averaged 9.1 MMcf of natural gas per day and 71 Bbls of oil per day, or 9.5 MMcfe per day.

Mobile 823 Field. Mobile 823 field is located off the coast of Alabama in approximately 60 feet of water. It is a natural gas field comprised of two OCS blocks, Mobile Blocks 822 and 823. The field was discovered by Mobil Oil Corporation in 1983, with initial production commencing in 1991. We acquired our 12.5% working interest in 2003 from ConocoPhillips. ExxonMobil currently operates the majority of the field. We operate one well, a Miocene "Luce" sand discovery drilled in 2006. Production is primarily from the Jurassic Norphlet sandstone at 21,500 feet, with minor production from Miocene sands at 3,000 to 7,000 feet. The trapping mechanism is a combination structural and stratigraphic trap. Cumulative field production through 2008 is approximately 774 Bcfe gross from eleven productive wells. The field has one processing platform and three independent structures. During December 2008, production from this field, net to our interest, averaged 7.6 MMcf of natural gas per day.

Ship Shoal 299 Field. Ship Shoal 299 field is 60 miles south and west of Grand Isle, Louisiana in water depths ranging from 250 feet to 300 feet. The field includes OCS blocks Ship Shoal 300, 314 and 315. Our working interests range from 75% to 100% and were acquired through the Kerr-McGee merger transaction and subsequent farmout transactions. The field was discovered in 1989 by Kerr-McGee with production commencing in 1992. There are three active platforms in the field. Production is primarily from the Ang B and Cris S Sands. As of December 31, 2008, 27 wells have been drilled of which 19 have been successful. Cumulative field production through 2008 is approximately 140 Bcfe gross. In December 2008, production from this field was shut-in due to Hurricanes Gustav and Ike. During July 2008 (prior to Hurricanes Gustav and Ike), production from this field, net to our interest, averaged 4.1 MMcf of natural gas per day and 2,403 Bbls of oil per day, or 18.5 MMcfe per day. We restored the majority of the field's oil production in February 2009 and we anticipate restoring gas production and the remaining oil production in the second quarter of 2009.

South Timbalier 228 Field. South Timbalier 228 field is located 50 miles off the coast of Louisiana in about 220 feet of water and includes South Timbalier blocks 229 and 230. The field was discovered in November 1994 by The Louisiana Land and Exploration Company. We acquired South Timbalier block 229 from Burlington Resources and became operator of the field in November 2002. We acquired South Timbalier block 230 in OCS Lease Sale 194, with an effective date of June 2005. We are a 100% working interest owner in this field. We have drilled six wells since becoming operator, all of which were successful. All the producing sands are within the basal Nebraskan section. Cumulative production from this field through 2008 is approximately 27 Bcfe gross. During December 2008, production from this field, net to our interest, averaged 1.7 MMcf of natural gas per day and 1,183 Bbls of oil per day, or 8.8 MMcfe per day.

West Delta 30 Field. West Delta 30 field is located approximately six miles off the coast of Louisiana in 40 feet of water. Our interests in this field are in West Delta Block 29, which straddles the eastern side of a major piercement salt dome with large accumulations of oil and natural gas sands found in traps along the salt flanks. In 1997, we entered into a farmout agreement with ChevronTexaco to further explore and develop potential reserves. Following a thorough 3-D seismic analysis, we have drilled a total of 17 exploration and development wells, all but one of which have been successful. Our working interests in these wells range from 37.5% to 100%. Cumulative field production through 2008 is approximately 698 Bcfe gross. During December 2008, production from this field, net to our interest, averaged 0.6 MMcf of natural gas per day and 641 Bbls of oil per day, or 4.4 MMcfe per day.

Proved Reserves

Our proved reserves at December 31, 2008 totaled 491.1 Bcfe. Approximately 68% of our reserves were classified as proved developed and 32% were classified as proved undeveloped. Classified by product, 46% of our reserves were natural gas and 54% were oil and natural gas liquids. 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, 2008 are summarized below.

	As of December 31, 2008				
Classification of Reserves	Oil (MMBbls)	Gas (Bcf)	Total (Bcfe)	% of Total Proved	PV-10 (2) (In millions)
Proved developed producing	8.6	96.8	148.6	30%	$234.5
Proved developed non-producing (1)	16.0	89.5	185.5	38%	397.4
Total proved developed	24.6	186.3	334.1	68%	631.9
Proved undeveloped	19.3	41.6	157.0	32%	299.0
Total proved	43.9	227.9	491.1	100%	$930.9

(1) Includes approximately 53.9 Bcfe of reserves with a PV-10 of $104.9 million that were shut-in at December 31, 2008 because of damage caused by Hurricane Ike in September 2008. We anticipate that most of these reserves will be reclassified to producing in 2009.

(2) We refer to PV-10 as the present value of estimated future net revenues before asset retirement obligations, as calculated by our independent petroleum consultant, adjusted by the Company to include estimated asset retirement obligations discounted using a 10% annual discount rate and using the same estimated useful

lives as those used in our calculation of asset retirement obligations under Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. PV-10 is not a financial measure prescribed under generally accepted accounting principles ("GAAP"); therefore, the following table reconciles our calculation of PV-10 to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Management believes that PV-10 is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, professional analysts and sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Management also uses this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating us. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. The PV-10 and standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves at December 31, 2008 are as follows (in millions):

	At December 31, 2008
Present value of estimated future net revenues before asset retirement obligations	$1,371.8
Present value of estimated asset retirement obligations, discounted at 10%	(440.9)
Present value of estimated future net revenues (PV-10)	930.9
Future income taxes, discounted at 10%	(169.2)
Standardized measure of discounted future net cash flows	$ 761.7

Acreage

The following summarizes gross and net developed and undeveloped acreage at December 31, 2008. Net acreage is our percentage ownership of gross acreage. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	1,026,026	537,937	192,826	157,451	1,218,852	695,388
Deepwater	109,231	55,509	103,152	80,112	212,383	135,621
	1,135,257	593,446	295,978	237,563	1,431,235	831,009

Approximately 79% of our total gross acreage is held-by-production, which permits us to maintain all of our exploration, exploitation and development rights (including deep rights below currently producing zones) to the leased area as long as production continues. We have the right to propose future exploration and development projects, including deep exploration projects, on the majority of our acreage.

Approximately 21% of our total gross acreage is undeveloped leasehold. Of our 295,978 total gross undeveloped acres, approximately 45% could expire in 2009, 19% in 2010, 6% in 2011, none in 2012 and 30% in 2013 and beyond, if not extended by exploration and production activities prior to the applicable lease expiration dates. Our drilling activity for 2009 will give consideration to our undeveloped leasehold that may expire in 2009 in order to retain the opportunity to exploit such lease acreage, based on the appropriate technical criteria, before expiration of the lease.

Production

During 2008, our net production averaged approximately 267.5 MMcfe per day. Approximately 21.7 Bcfe of net production was deferred during 2008 as a result of damage caused by Hurricane Ike and, to a lesser extent, by Hurricane Gustav.

Production History

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

	Year Ended December 31,		
	2008	2007	2006
Net sales:			
Natural gas (Bcf)	56.1	76.7	60.4
Oil (MMBbls)	7.0	8.3	6.5
Total natural gas and oil (Bcfe)	97.9	126.5	99.2

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

Productive Wells

The following presents our ownership interest at December 31, 2008 in our productive oil and natural gas wells, including wells that were temporarily shut-in on that date primarily because of Hurricane Ike in 2008. 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	121	104.8	142	106.3	263	211.1
Non-operated	134	36.9	146	34.4	280	71.3
	255	141.7	288	140.7	543	282.4

(1) Includes 12 gross (7.5 net) oil wells and 10 gross (4.8 net) gas wells with multiple completions.

Our ownership in wells that were temporarily shut-in at December 31, 2008 primarily because of Hurricane Ike in 2008 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	60	46.8	32	23.1	92	69.9
Non-operated	75	19.7	69	13.0	144	32.7
	135	66.5	101	36.1	236	102.6

Drilling Activity

During 2008, we participated in the drilling of 24 gross exploratory wells and two gross development wells of which 21 were on the conventional shelf and five were on the deep shelf. Both of the development wells were successful and 18 of the exploratory wells were successful. We operate 12 of the 18 successful exploratory wells.

The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2008, capital expenditures for oil and gas properties of $774.9 million included $116.6 million for the acquisition of Apache's interest in Ship Shoal 349 field, $337.6 million for exploration activities, $265.3 million for development activities and $55.4 million for seismic, capitalized interest and other leasehold costs.

Development Drilling

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

	Year Ended December 31,		
	2008	2007	2006
Gross Wells:			
Productive	2	2	8
Non-productive	—	—	—
	2	2	8
Net Wells:			
Productive	1.7	1.1	6.0
Non-productive	—	—	—
	1.7	1.1	6.0

Exploration Drilling

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

	Year Ended December 31,		
	2008	2007	2006
Gross Wells:			
Productive	18	6	19
Non-productive	6	1	7
	24	7	26
Net Wells:			
Productive	12.3	4.2	14.7
Non-productive	4.4	0.7	5.6
	16.7	4.9	20.3

Current Drilling Activity

During the period beginning January 1, 2009 and ending February 20, 2009, we participated in the drilling of three gross (2.5 net) successful exploratory wells and one gross (0.5 net) unsuccessful development well. We were in the process of drilling one gross (0.5 net) exploratory well as of February 20, 2009.

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*

No matters were submitted to a vote of our security holders during the fourth quarter of 2008.

Executive Officers of the Registrant

The following lists our executive officers:

Name	Age	Position
Tracy W. Krohn	54	Founder, Chairman, Director and Chief Executive Officer
J.F. Freel	96	Founder, Chairman Emeritus, Director and Secretary
Jamie L. Vazquez	48	President
W. Reid Lea	50	Executive Vice President and Manager of Corporate Development
John D. Gibbons	55	Senior Vice President, Chief Financial Officer and Chief Accounting Officer
Stephen L. Schroeder	46	Senior Vice President and Chief Operating Officer

Tracy W. Krohn has served as Chief Executive Officer since he founded the Company in 1983 and as Chairman since 2004. He also served as President of the Company until September 2008. Mr. Krohn's mother is married to Mr. J.F. Freel.

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

Jamie L. Vazquez joined the Company in 1998 as Manager of Land and in 2003 she was named Vice President of Land. In September 2008, Ms. Vazquez was appointed President of the Company.

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

John D. Gibbons joined the Company in February 2007 as Senior Vice President and Chief Financial Officer. In September 2007, he assumed the additional position of Chief Accounting Officer.

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

PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the symbol "WTI." The following sets forth, for each of the periods indicated, the high and low sales price of our common stock as reported on the New York Stock Exchange.

	High	Low
2007		
First Quarter	$33.20	$25.76
Second Quarter	32.07	26.97
Third Quarter	28.10	20.53
Fourth Quarter	31.00	23.59
2008		
First Quarter	39.39	26.41
Second Quarter	59.99	33.40
Third Quarter	59.99	25.20
Fourth Quarter	27.01	9.99

As of February 20, 2009, there were 299 registered holders of our common stock.

Dividends

Under the Credit Agreement, we are allowed to pay annual dividends if we are not in default. On July 24, 2008, certain amendments were made to the Credit Agreement, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year. In addition, the indenture governing the Notes contains restrictions on the payment of dividends unless we meet the restricted payment tests in the indenture. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*" and Note 6 to our consolidated financial statements for more information regarding our Credit Agreement and the indenture governing the Notes.

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

	Aggregate Dividends on Common Stock	Dividend per Share of Common Stock
2007		
First Quarter	$ 2,287	$0.03
Second Quarter	2,286	0.03
Third Quarter	2,287	0.03
Fourth Quarter (1)	32,286	0.42
2008		
First Quarter	2,291	0.03
Second Quarter	2,291	0.03
Third Quarter	2,291	0.03
Fourth Quarter (2)	20,840	0.27

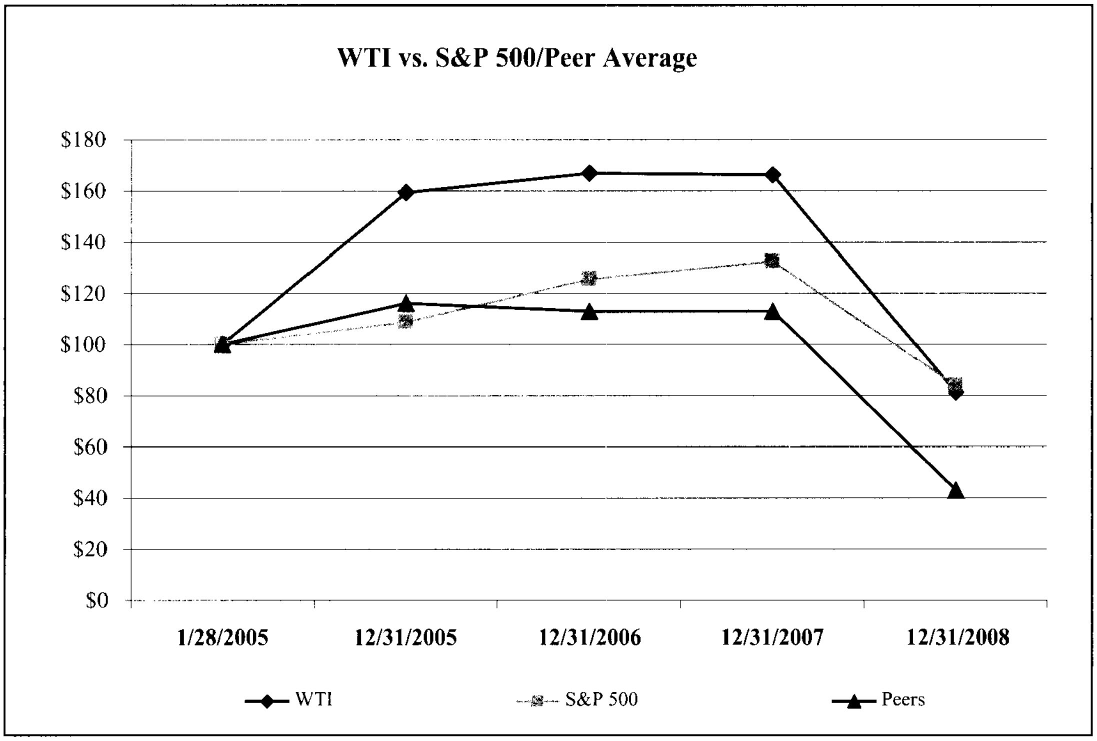
(1) Includes a special cash dividend of approximately $0.39 per share and a regular cash dividend of $0.03 per share.

(2) Consists of a special cash dividend only.

With the exception of any special cash dividends, 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. On February 25, 2009, our board of directors declared a cash dividend of $0.03 per common share, payable on March 20, 2009 to shareholders of record on March 6, 2009.

Stock Performance Graph

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



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

Issuer Purchases of Equity Securities

On July 24, 2008, certain amendments were made to the Credit Agreement, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year. Effective December 18, 2008, the Credit Agreement was further amended to allow for, among other things, the repurchase of our common stock and/or Notes in an aggregate amount not to exceed $100.0 million (over the life of the Credit Agreement). The December 18, 2008 amendment does not limit the dividend or share repurchase availability that was changed in connection with the amendment to the Credit Agreement on July 24, 2008.

No repurchases of either common stock or the Notes occurred during the three month period ended December 31, 2008, as the Company currently does not have a stock or debt repurchase program in place. The table below sets forth information about shares delivered by employees to satisfy tax withholding obligations on the vesting of restricted shares.

Period	Total Number of Shares Delivered	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
December 1, 2008 – December 31, 2008	61,692	$13.49	N/A	N/A

Item 6. *Selected 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 (loss) 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,				
	2008	2007	2006 (1)	2005	2004
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income (Loss) Information:					
Revenues:					
Natural gas	$ 527,352	$ 552,687	$ 427,839	$384,985	$329,947
Oil	688,097	560,940	372,509	199,579	178,248
Other	160	122	118	572	520
Total revenues	1,215,609	1,113,749	800,466	585,136	508,715
Operating costs and expenses:					
Lease operating expenses (2)	229,747	234,758	113,993	75,732	77,431
Production taxes	8,827	5,921	1,556	712	375
Gathering and transportation	15,957	15,526	16,141	11,990	13,724
Depreciation, depletion and amortization	482,464	510,903	325,131	174,771	155,640
Asset retirement obligation accretion	39,312	22,007	12,496	9,062	9,168
Impairment of oil and natural gas properties (3)	1,182,758	—	—	—	—
General and administrative expenses (4)(5)(6)	47,225	38,853	37,778	24,444	21,045
Derivative loss (gain) (7)	16,464	36,532	(24,244)	—	—
Total costs and expenses	2,022,754	864,500	482,851	296,711	277,383
Operating income (loss)	(807,145)	249,249	317,615	288,425	231,332
Interest expense, net of amounts capitalized	34,709	37,088	17,180	1,145	2,118
Loss on extinguishment of debt (8)	—	2,806	—	—	—
Other income (9)	13,372	6,404	5,919	2,746	276
Income (loss) before income taxes	(828,482)	215,759	306,354	290,026	229,490
Income tax expense (benefit)	(269,663)	71,459	107,250	101,003	80,008
Net income (loss)	(558,819)	144,300	199,104	189,023	149,482
Less preferred stock dividends	—	—	—	—	900
Net income (loss) applicable to common shares	$ (558,819)	$ 144,300	$ 199,104	$189,023	$148,582
Earnings (loss) per common share:					
Basic	$ (7.36)	$ 1.90	$ 2.84	$ 2.91	$ 2.82
Diluted	(7.36)	1.90	2.84	2.87	2.27
Dividends on common stock (10)	27,713	39,146	8,522	5,938	3,550
Cash dividends per common share (10)	0.36	0.51	0.12	0.09	0.07
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 882,496	$ 688,597	$ 571,589	$444,043	$377,275
Capital expenditures – oil and gas properties	774,879	361,235	1,650,747	322,984	282,510
Other Financial Information:					
EBITDA (11)	$ 897,389	$ 779,353	$ 655,242	$472,258	$396,140
Adjusted EBITDA (11)	883,888	819,990	641,766	472,258	396,140

	December 31,				
	2008	2007	2006	2005	2004
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 357,552	$ 314,050	$ 39,235	$ 187,698	$ 64,975
Total assets	2,056,186	2,812,204	2,609,685	1,064,520	760,784
Long-term debt	653,172	654,764	684,997	40,000	35,000
Shareholders' equity	572,227	1,151,340	1,042,917	543,383	359,878

(1) In August 2006, we acquired working interests in approximately 100 oil and gas fields on 242 offshore blocks located in the Gulf of Mexico from Kerr-McGee by merger.

(2) Included in lease operating expenses for the year ended December 31, 2008 is $17.7 million of hurricane remediation costs related to Hurricanes Ike and Gustav that were either not covered by insurance or have yet to be recovered from our insurance underwriters. Included in lease operating expenses for the years ended December 31, 2007, 2006 and 2005 are $18.5 million, $0.5 million and $1.6 million, respectively, for hurricane remediation costs that were not covered by insurance. In 2005, we capitalized $3.4 million of hurricane remediation costs that were not covered by insurance.

(3) In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion ($768.8 million after-tax) through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008. No such write-downs were required during the other years presented.

(4) The amounts for 2007, 2006 and 2005 include expenses of $0.6 million, $2.1 million and $2.4 million, respectively, associated with the temporary displacement of the employees who worked in our operations office in Metairie, Louisiana due to damage caused by Hurricane Katrina and the subsequent relocation of the majority of those employees to Houston, Texas. The amounts for 2005 and 2004 include expenses of $0.9 million and $1.5 million, respectively, associated with our initial public offering, which was completed in January 2005.

(5) 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 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.

(6) G&A expenses related to our long-term incentive compensation plans were $11.6 million, $7.8 million, $8.4 million, $2.3 million and $0.6 million in 2008, 2007, 2006, 2005 and 2004, respectively.

(7) In 2008, our derivative loss of $16.5 million consisted of a realized loss of $27.4 million related to settlements of our commodity derivative contracts offset by a change in the fair value of our commodity derivative contracts of $17.4 million. As of December 31, 2008, we had no remaining open commodity derivative contracts. Also included in 2008 are realized and unrealized losses of $2.6 million and $3.9 million, respectively, related to our interest rate swap that was de-designated as a cash flow hedge during 2007. In 2007, our derivative loss of $36.5 million consisted of an unrealized loss of $34.3 million offset by a realized gain of $1.3 million related to our commodity derivative contracts. Also included in 2007 is an unrealized loss of $3.5 million related to our interest rate swap. In 2006, our derivative gain of $24.2 million consisted of realized and unrealized gains of $10.7 million and $13.5 million, respectively, related to our commodity derivative contracts. We did not engage in any hedging transactions during the other years presented.

(8) In June 2007, we used a portion of the proceeds from our private offering of the Notes to prepay the balance outstanding on our Tranche A term loan facility and make a $90.0 million principal payment on our Tranche B term loan facility. A loss of $2.8 million was incurred related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility.

(9) Consists of interest income.

(10) The amount for 2008 includes a special cash dividend of $20.84 million, or approximately $0.2729 per share, that was paid in December 2008. The amount for 2007 includes a special cash dividend of $30.0 million, or approximately $0.39 per share, that was declared in December 2007 and paid in January 2008.

(11) EBITDA and Adjusted EBITDA are non-GAAP financial measures. We define EBITDA as net income (loss) plus income tax expense (benefit), net interest expense (income), depreciation, depletion, amortization and accretion and impairment of oil and natural gas properties. Adjusted EBITDA excludes the loss on extinguishment of debt and the unrealized gain or loss related to our derivative contracts. Although not prescribed under generally accepted accounting principles, we believe the presentation of EBITDA and Adjusted EBITDA provide useful information regarding our ability to service debt and fund capital expenditures and they help our investors understand our operating performance and make it easier to compare our results with those of other companies that have different financing, capital and tax structures. EBITDA and Adjusted EBITDA should not be considered in isolation from or as a substitute for net income,

as an indication of operating performance or cash flow from operating activities or as a measure of liquidity. EBITDA and Adjusted EBITDA, as we calculate them, may not be comparable to EBITDA and Adjusted EBITDA measures reported by other companies. In addition, EBITDA and Adjusted EBITDA do not represent funds available for discretionary use. A reconciliation of our consolidated net income (loss) to EBITDA and Adjusted EBITDA is as follows:

	Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(Dollars in thousands)				
Net income (loss)	$ (558,819)	$144,300	$199,104	$189,023	$149,482
Income tax expense (benefit)	(269,663)	71,459	107,250	101,003	80,008
Net interest expense (income)	21,337	30,684	11,261	(1,601)	1,842
Depreciation, depletion, amortization and accretion	521,776	532,910	337,627	183,833	164,808
Impairment of oil and natural gas properties	1,182,758	—	—	—	—
EBITDA	897,389	779,353	655,242	472,258	396,140
Loss on extinguishment of debt	—	2,806	—	—	—
Unrealized derivative (gain) loss	(13,501)	37,831	(13,476)	—	—
Adjusted EBITDA	$ 883,888	$819,990	$641,766	$472,258	$396,140

HISTORICAL RESERVE AND OPERATING INFORMATION

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

	December 31,				
	2008	2007	2006	2005	2004
Reserve Data:					
Estimated net proved reserves (1):					
Natural gas (Bcf)	227.9	332.8	401.2	215.9	227.6
Oil (MMBbls)	43.9	51.0	55.7	45.9	40.0
Total natural gas and oil (Bcfe)	491.1	638.8	735.2	491.5	467.5
Proved developed producing (Bcfe)	148.6	224.1	225.3	120.1	145.8
Proved developed non-producing (Bcfe) (2)	185.5	171.2	253.6	198.5	144.4
Total proved developed (Bcfe)	334.1	395.3	478.9	318.6	290.2
Proved undeveloped (Bcfe)	157.0	243.5	256.3	172.9	177.3
Proved developed reserves as a percentage of proved reserves	68.0%	61.9%	65.1%	64.8%	62.1%
Reserve additions (reductions) (Bcfe):					
Revisions (3)	(157.5)	(18.7)	(13.1)	20.3	20.9
Extensions and discoveries	47.2	48.4	109.3	60.6	65.2
Purchases of minerals in place	60.5	1.4	246.7	14.2	19.2
Sales of minerals in place	—	(1.0)	—	—	(0.1)
Production	(97.9)	(126.5)	(99.2)	(71.1)	(82.4)
Net reserve additions (reductions)	(147.7)	(96.4)	243.7	24.0	22.8

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Operating Data:					
Net sales:					
Natural gas (Bcf)	56.1	76.7	60.4	46.5	53.3
Oil (MMBbls)	7.0	8.3	6.5	4.1	4.8
Total natural gas and oil (Bcfe) (1)	97.9	126.5	99.2	71.1	82.4
Average daily equivalent sales (MMcfe/d)	267.5	346.7	271.7	194.7	225.2
Average realized sales prices (Unhedged):					
Natural gas ($/Mcf)	$ 9.40	$ 7.20	$ 7.08	$ 8.27	$ 6.18
Oil ($/Bbl)	98.72	67.58	57.70	48.85	36.77
Natural gas equivalent ($/Mcfe)	12.42	8.80	8.07	8.23	6.16
Average realized sales prices (Hedged) (4):					
Natural gas ($/Mcf)	$ 9.42	$ 7.28	$ 7.23	$ 8.27	$ 6.18
Oil ($/Bbl)	94.67	67.01	57.97	48.85	36.77
Natural gas equivalent ($/Mcfe)	12.14	8.81	8.18	8.23	6.16
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 2.35	$ 1.86	$ 1.15	$ 1.07	$ 0.94
Gathering and transportation costs and production taxes	0.25	0.17	0.18	0.18	0.17
Depreciation, depletion, amortization and accretion	5.33	4.21	3.40	2.59	2.00
General and administrative expenses	0.48	0.31	0.38	0.34	0.26
	$ 8.41	$ 6.55	$ 5.11	$ 4.18	$ 3.37
Total number of wells drilled (gross)	26	9	34	29	39
Total number of productive wells drilled (gross)	20	8	27	23	28

(1) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).
(2) Approximately 53.9 Bcfe of reserves were shut-in at December 31, 2008 because of damage caused by Hurricane Ike in September 2008. We anticipate that most of these reserves will be reclassified to producing in 2009. Approximately 20.2 Bcfe and 23.5 Bcfe of reserves were shut-in at December 31, 2006 and 2005, respectively, because of Hurricanes Katrina and Rita in 2005. Also, approximately 5.7 Bcfe of reserves were shut-in at December 31, 2006 because of damage to the High Island Pipeline System which occurred in December 2006.
(3) For 2008, negative revisions due to pricing, performance and hurricane damage were 105.0 Bcfe, 42.4 Bcfe and 10.1 Bcfe, respectively.
(4) Data for 2008, 2007 and 2006 includes the effects of our commodity derivative contracts that did not qualify for hedge accounting. We did not have any commodity derivative contracts in place during 2005 and 2004.

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 an independent oil and natural gas producer focused in the Gulf of Mexico. We have grown through acquisitions, exploitation and exploration and currently hold working interests in approximately 148 producing fields in federal and state waters. We operate wells accounting for approximately 69% of our average daily production. In recent years, we have acquired interests in acreage and wells in the deepwater (more than 500 feet of water) on the outer continental shelf. We have interests in leases covering approximately 1.4 million gross acres (0.8 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama. We own interests in approximately 516 platforms, 328 of which are located in fields that we operate.

In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on profitably increasing production and reserves. We do not seek to increase production and reserves for the sake of growth. Rather, we acquire reserves or explore for new reserves where we believe we can achieve a rate of return on shareholders' equity over any five-year period comparable to our historic average. Our ability to control our costs in the past has helped contribute to our growth. However, following Hurricanes Katrina and Rita in 2005, costs for goods and services escalated rapidly with only intermittent declines, followed by additional escalation through most of 2008. 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 rate 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 will enable us to continue to add reserves post-acquisition.

On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee by merger for approximately $1.1 billion. The properties acquired included interests in approximately 100 fields on 242 offshore blocks spreading across the Western, Central and Eastern U.S. Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, bank financing and proceeds from a public offering of our common stock.

On December 21, 2007, we entered into an agreement with Apache Corporation to acquire its interest in Ship Shoal 349 field for $116.6 million in cash. This field is located off the coast of Louisiana and covers two federal offshore lease blocks, Ship Shoal blocks 349 and 359. The transaction closed on January 29, 2008, with an effective date of January 1, 2008. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and gas reserves acquired were 60.5 Bcfe. This acquisition was funded from cash on hand. For additional details about this transaction, refer to Note 4 to our consolidated financial statements.

Our exploration efforts are balanced between discovering reserves associated with acquisitions and reserves associated with 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, 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 participants to share the risk.

We generally sell our oil and natural gas at current market prices at the wellhead or we transport our production to "pooling points" where it is sold. We are required to pay gathering and transportation costs with respect to a majority of our products. We market our products several different ways depending upon a number of factors, including the availability of purchasers at the wellhead, the availability and cost of pipelines near the well or related production platforms, the availability of third party processing capacity, market prices, pipeline constraints and operational flexibility.

During 2008, we sold an average of approximately 153 MMcf of natural gas per day and approximately 19,000 Bbls of oil per day, or a combined rate of 267 MMcfe per day. As a result of Hurricane Gustav in late August 2008 and Hurricane Ike in early September 2008, our production was negatively affected by downtime experienced by third party pipelines and processing facilities and, to a lesser extent, by damage to our facilities. Our sales during the fourth quarter of 2008 averaged approximately 176 MMcfe per day.

Market prices for oil and natural gas escalated in 2008 until a collapse in the credit markets occurred, signaling the presence of a global economic recession. Although market prices for oil and natural gas were sharply lower in the fourth quarter, our revenues in 2008 benefited from higher average realized prices on sales of our oil and natural gas over the course of the entire year. Current market prices for oil and natural gas continue to be depressed and therefore our revenues, cash flows and earnings for 2009 are expected to be significantly lower compared to 2008.

As of December 31, 2008, we did not have any open commodity derivative positions. In 2008, we recorded a realized loss of $27.4 million related to settlements of our commodity derivative contracts offset by a change in the fair value of our commodity derivative contracts of $17.4 million. In 2007 and 2006, we recorded realized gains of $1.3 million and $10.7 million, respectively, and we recorded an unrealized loss of $34.3 million and an unrealized gain of $13.5 million, respectively, related to our commodity derivatives.

Our operating costs include 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, repairs and maintenance, gathering and transportation costs, production taxes, workover costs and ad valorem taxes. Our operating costs depend in part on 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 began operating wells in the deepwater of the Gulf of Mexico. To the extent we continue our deepwater operations, our operating costs will likely increase. While each field can present operating problems that can add to the costs of operating a field, the production costs of a field are generally directly proportional to the number of production platforms built in the field. As technologies have improved, oil and natural gas can be produced from larger acreage areas using a single platform, which may reduce the operating costs associated with future development projects.

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 asset retirement obligations generally increase as we drill wells in deeper parts of the continental shelf and in the deepwater. We generally do not pre-fund our asset retirement obligations. Our asset retirement obligations were estimated to be $547.9 million at December 31, 2008, discounted at a weighted average rate of 8.1%.

Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues. Revenues increased $101.9 million, or 9%, to $1.2 billion for the year ended December 31, 2008. The increase in revenues was comprised of a price increase of $338.1 million, partially offset by a sales volume decrease of $236.2 million. Oil revenues increased $127.2 million and natural gas revenues decreased $25.3 million. The oil revenue increase was caused by a 46.1% increase in the average realized price to $98.72 per barrel in 2008 from $67.58 per barrel in 2007, partially offset by a 15.7% decrease in sales volumes. The natural gas revenue decrease resulted from a 26.9% decrease in sales volumes, partially offset by a 30.6% increase in the average realized natural gas price to $9.40 per Mcf in 2008 from $7.20 per Mcf in 2007. Sales volumes for oil and natural gas declined in 2008 primarily due to the deferral of production caused by Hurricane Gustav in late August 2008 and Hurricane Ike in early September 2008, partially offset by increases resulting from our successful exploration and development efforts, the acquisition of Apache's interest in Ship Shoal 349 field and several recompletions. Prior to Hurricane Gustav our production was averaging approximately 324 MMcfe per day. After the hurricanes we were almost totally shut-in for about a month, and when production resumed we were producing about 72 MMcfe per day. Following a slow ramp up, our exit rate at the end of 2008 was 221 MMcfe per day and is expected to continue to increase as third party pipelines and processing facilities return to service. We believe that approximately 21.7 Bcfe of net production was deferred during 2008 as a result of damage caused by Hurricane Ike and, to a lesser extent, by Hurricane Gustav.

Lease operating expenses. Lease operating expenses, which includes base lease operating expenses, insurance costs, workovers and repairs and maintenance on our facilities, increased to $2.35 per Mcfe in 2008 from $1.86 per Mcfe in 2007. Lower production volumes during 2008 resulted in an increase in lease operating expenses per Mcfe of $0.54, which was partially offset by a decrease of $0.05 per Mcfe caused by lower lease operating expenses. On a nominal basis, lease operating expenses decreased $5.0 million to $229.8 million in 2008 compared to 2007. The decrease of $5.0 million is attributable to decreases in insurance costs, facility expenditures and hurricane repair costs of $4.2 million, $1.4 million and $0.8 million, respectively, and lower workover expenditures of $6.8 million primarily associated with various non-operated properties. Offsetting these decreases was an increase in base lease operating expenses of $8.2 million. The increase in base lease operating expenses is primarily related to the acquisition of an additional interest in Ship Shoal 349 from Apache, increases in field salaries and incentive compensation and higher fuel costs. Included in lease operating expenses for 2008 is $17.7 million of hurricane remediation costs related to Hurricanes Ike and Gustav that were either not covered by insurance or have yet to be recovered from our insurance underwriters. Lease operating expenses will be offset in future periods to the extent that these expenses are recovered under our insurance policy. The 2007 period included $18.5 million of hurricane remediation costs related to Hurricanes Katrina and Rita that were not covered by insurance.

Production taxes. Production taxes increased $2.9 million to $8.8 million in 2008 primarily due to new production from fields in state waters of Texas and Louisiana and higher realized prices on sales of our oil and natural gas. Most of our production is from federal waters, where there are no production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $0.4 million to $16.0 million in 2008 primarily due to an increase in third-party processing fees for the production of natural gas liquids, partially offset by the deferral of production caused by Hurricanes Ike and Gustav.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion ("DD&A") decreased to $521.8 million in 2008 from $532.9 million in 2007. The decrease is primarily attributable to lower volumes of oil and natural gas produced in 2008, partially offset by capital expenditures, an increase in our estimated asset retirement obligations of $111.1 million (see Note 2 to our consolidated financial statements) and lower total proved reserves in 2008. Total proved reserves decreased 147.7 Bcfe to 491.1 Bcfe at December 31, 2008 from 638.8 Bcfe at December 31, 2007, a net reduction of 23.1%. This decrease in reserves is largely due to the significant decline in both oil and natural gas prices as of December 31, 2008. On a per Mcfe basis, DD&A was $5.33 for the year ended December 31, 2008, compared to $4.21 for the same period in 2007.

Impairment of oil and natural gas properties. In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008.

General and administrative expenses. General and administrative expenses ("G&A") increased to $47.2 million for the year ended December 31, 2008 from $38.9 million in the same period of 2007 primarily due to an increase in the number of employees and higher salaries and other employee benefits. G&A expenses related to our long-term incentive compensation plans were $11.6 million and $7.8 million in the years ended December 31, 2008 and 2007, respectively (see Note 13 to our consolidated financial statements).

Derivative loss/gain. For the year ended December 31, 2008, our derivative loss of $16.5 million consisted of a realized loss of $27.4 million related to settlements of our commodity derivative contracts offset by a change in the fair value of our commodity derivative contracts of $17.4 million. As of December 31, 2008, we had no remaining open commodity derivative contracts. Also included in 2008 are realized and unrealized losses of $2.6 million and $3.9 million, respectively, related to our interest rate swap that was de-designated as a cash flow hedge during 2007. For the year ended December 31, 2007, our derivative loss of $36.5 million consisted of an unrealized loss of $34.3 million offset by a realized gain of $1.3 million related to our commodity derivative contracts. Also included in 2007 is an unrealized loss of $3.5 million related to our interest rate swap that was de-designated as a cash flow hedge during 2007. For additional details about our derivatives, refer to Note 8 to our consolidated financial statements.

Interest expense. Interest expense incurred decreased to $54.0 million for the year ended December 31, 2008 from $62.2 million in the same period of 2007 primarily due to a lower average interest rate and lower debt outstanding during 2008. During 2008 and 2007, $19.3 million and $25.1 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Other income. Other income, consisting of interest income, increased to $13.4 million for the year ended December 31, 2008 from $6.4 million in the same period of 2007 mainly due to higher average daily cash balances in 2008.

Income tax expense/benefit. An income tax benefit of $269.7 million was recorded in 2008, compared to income tax expense of $71.5 million in 2007. The income tax benefit in 2008 is primarily the result of an impairment of our oil and natural gas properties of $1.2 billion as described above. The effective rate of 32.5% for 2008 includes the federal statutory rate of 35.0%, reduced primarily by the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2007 was 33.1% and is below the statutory rate of 35% primarily because of the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues. Revenues increased \$313.3 million, or 39%, to \$1.1 billion for the year ended December 31, 2007. The increase in revenues was comprised of a price increase of \$90.2 million and a sales volume increase of \$223.1 million. Oil revenues increased \$188.4 million and natural gas revenues increased \$124.9 million. The oil revenue increase was caused by a 27.7% increase in sales volumes and a 17.1% increase in the average realized price to \$67.58 per barrel in 2007 from \$57.70 per barrel in 2006. The natural gas revenue increase was caused by a 27.0% increase in sales volumes and a 1.7% increase in the average realized natural gas price to \$7.20 per Mcf for the year ended December 31, 2007 from \$7.08 per Mcf for the same period in 2006. The volume increases for oil and natural gas are primarily attributable to properties acquired by merger in the Kerr-McGee transaction, resumed production from properties that underwent hurricane repairs and increased production from our successful drilling and development efforts, partially offset by properties that experienced natural reservoir declines.

Lease operating expenses. Lease operating expenses increased to \$1.86 per Mcfe for the year ended December 31, 2007 from \$1.15 per Mcfe in 2006, despite higher total sales volumes in 2007. On a nominal basis, lease operating expenses increased to \$234.8 million for the year ended December 31, 2007 from \$114.0 million in 2006. The increase of \$120.8 million is attributable to increases in base lease operating expenses of \$60.5 million, workover expenditures of \$10.9 million, major maintenance expenses of \$33.7 million (\$18.5 million of which is hurricane remediation costs) and \$15.7 million in higher insurance premiums. Approximately \$57.3 million of the increases in base lease operating expenses, workovers and major maintenance expenses are associated with properties acquired by merger in the Kerr-McGee transaction. We believe the incurrence of such costs following a large acquisition of properties is not unusual, and the magnitude and timing of additional workover and maintenance expenditures on the properties acquired by merger in the Kerr-McGee transaction may fluctuate as integration of the properties continues. The remainder of the increase in operating costs is primarily attributable to new production and an overall increase in service and supply costs. The \$18.5 million of hurricane remediation costs referred to above was not covered by insurance. Amounts spent in 2006 related to hurricane remediation efforts were covered by insurance (after applicable deductibles) and therefore were not included in lease operating expenses.

Gathering and transportation costs and production taxes. Gathering and transportation costs and production taxes increased to \$21.4 million in 2007 from \$17.7 million in 2006 primarily due to the acquisition of a field in Louisiana state waters that was part of the properties acquired by merger in the Kerr-McGee transaction. Most of our production is from federal waters, where there are no production taxes.

Depreciation, depletion, amortization and accretion. DD&A increased to \$532.9 million in 2007 from \$337.6 million in 2006. DD&A increased due to a number of factors including capital expenditures, an increase in future development costs of \$155.7 million, an increase in our estimated asset retirement obligations of \$161.9 million (see Note 2 to our consolidated financial statements) and higher volumes of oil and natural gas produced in 2007. In addition, total proved reserves decreased 13% to 638.8 Bcfe at December 31, 2007 from 735.2 Bcfe at December 31, 2006. On a per Mcfe basis, DD&A was \$4.21 for the year ended December 31, 2007, compared to \$3.40 for the same period in 2006.

General and administrative expenses. G&A increased to \$38.9 million for the year ended December 31, 2007 from \$37.8 million in the same period of 2006 primarily due to increases in the number of employees (and therefore greater compensation and benefits costs), office rent and a termination benefit under an employment contract in 2007. G&A expenses related to our long-term incentive compensation plans were \$7.8 million and \$8.4 million in the years ended December 31, 2007 and 2006, respectively (see Note 13 to our consolidated financial statements). Included in G&A for 2007 and 2006 are expenses of \$0.6 million and \$2.1 million, respectively, associated with the temporary displacement of the employees who worked in our operations office in Metairie, Louisiana due to damage caused by Hurricane Katrina and the subsequent relocation of the majority of those employees to Houston, Texas.

Derivative loss/gain. For the year ended December 31, 2007, our derivative loss of $36.5 million consisted of an unrealized loss of $34.3 million offset by a realized gain of $1.3 million related to our commodity derivative contracts. Also included in 2007 is an unrealized loss of $3.5 million related to our interest rate swap that was de-designated as a cash flow hedge during 2007. For the year ended December 31, 2006, our derivative gain of $24.2 million consisted of realized and unrealized gains of $10.7 million and $13.5 million, respectively, related to our commodity derivative contracts. For additional details about our derivatives, refer to Note 8 to our consolidated financial statements.

Interest expense. Interest expense incurred increased to $62.2 million for the year ended December 31, 2007 from $30.4 million in the same period of 2006 primarily due to debt incurred in August 2006 to finance a portion of the purchase price of properties acquired by merger in the Kerr-McGee transaction. During 2007 and 2006, $25.1 million and $13.2 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Loss on extinguishment of debt. In June 2007, we used a portion of the proceeds from the private offering of our Notes to prepay the balance outstanding on our Tranche A term loan facility and make a $90.0 million principal payment on our Tranche B term loan facility. For the year ended December 31, 2007, a loss of $2.8 million was incurred related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility.

Other income. Other income, consisting of interest income, increased to $6.4 million for the year ended December 31, 2007 from $5.9 million in the same period of 2006 mainly due to higher average daily cash balances in 2007.

Income tax expense. Income tax expense decreased to $71.5 million in 2007 from $107.3 million in 2006 primarily due to a decrease in pre-tax income. Our effective tax rate for the year ended December 31, 2007 was 33.1% and is below the statutory rate of 35% primarily because of the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code. For the year ended December 31, 2006, our effective tax rate was 35.0%. In 2006, the Company experienced a net loss for tax purposes and as a result, the qualified domestic production activities deduction was not available to us.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures to allow us to replace our oil and natural gas reserves, repay outstanding borrowings and make related interest payments and to fund strategic property acquisitions. We have funded our capital expenditures, including acquisitions, with cash on hand, cash provided by operations, securities offerings, bank borrowings and other long-term debt. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

Cash flow and working capital. Net cash provided by operating activities for the year ended December 31, 2008 was $882.5 million, compared to $688.6 million for 2007. Net cash used in investing activities totaled $773.9 million and $360.1 million during 2008 and 2007, respectively, which primarily represents our investment in oil and gas properties. During 2008, we reduced debt by $3.0 million and increased cash by $43.5 million. As of December 31, 2008, we had positive working capital of $196.9 million and current maturities of our long-term debt totaled $3.0 million.

At December 31, 2008, we had $500.0 million of undrawn capacity available under the revolving portion of the Credit Agreement. Under the terms of the Credit Agreement, we are subject to various financial covenants calculated as of the last day of each fiscal quarter. As of December 31, 2008, we were in compliance with such financial covenants. See "*Long-term debt*" and Note 6 to our consolidated financial statements for more information regarding our Credit Agreement.

Increases in our operating cash flows from 2006 through 2008 are attributable to several factors. In 2008, operating cash flows were favorably impacted by increases in the average prices we realized on sales of our oil and natural gas, lower interest expense incurred and higher interest income, as compared to 2007. Offsetting these favorable factors were lower volumes of oil and natural gas sold, realized losses on settlements of our commodity derivative contracts and higher general and administrative expenses, as compared to 2007. In 2007, operating cash flows were favorably impacted by higher volumes of oil and natural gas sold primarily due to the Kerr-McGee transaction and increases in the average prices we realized on sales of our oil and natural gas, as compared to 2006. Offsetting these favorable factors were higher operating costs and interest expense in 2007 primarily due to the Kerr-McGee transaction, and lower realized gains on settlements of our commodity derivative contracts, as compared to 2006.

Oil and natural gas prices reached record levels in 2008 and as a result our EBITDA, earnings and operating cash flow for the first nine months of 2008 were also at record levels. During the first nine months of 2008, our average realized price on sales of our oil and natural gas was $13.56 per Mcfe. However, our operating costs on a per Mcfe basis during the first nine months of 2008 were also at record levels at $7.68 per Mcfe. Oil prices peaked at over $145 per barrel in early July 2008 and then declined to approximately $41 per barrel by the end of 2008. Natural gas prices similarly declined from a high of approximately $13.50 per Mcf in July 2008 to approximately $5.70 per Mcf by the end of 2008. Although our average realized price on sales of our oil and natural gas has declined dramatically, our average operating cost has not dropped proportionately.

As a result of Hurricanes Ike and Gustav, our production and cash flow were negatively affected by the downtime experienced by third party pipelines and processing facilities and, to a lesser extent, by damage to our facilities. Prior to Hurricane Gustav in late August 2008, our production was averaging approximately 324 MMcfe per day. Our production was shut-in for nearly a month as a result of the these two hurricanes, and during October 2008 our production was only 134 MMcfe per day. During the fourth quarter our production averaged approximately 176 MMcfe per day and our exit rate at the end of 2008 was approximately 221 MMcfe per day. As a result of both lower production and lower prices of oil and natural gas, our operating cash flow decreased dramatically in the fourth quarter of 2008 compared to the other quarters of 2008. Prices have continued to weaken into early 2009 but our production has been rising with the return to service of third party pipelines and processing facilities. At current price levels cash flow from operations for 2009 will be lower than 2008.

We have used various derivative instruments from time to time to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. In January 2006, we entered into commodity swap and option contracts (as required by the Credit Agreement) relating to approximately 14 Bcfe, or 14%, of our production in 2006, 18 Bcfe, or 14%, of our production in 2007 and 11 Bcfe, or 11%, of our production in 2008 in connection with the anticipated financing related to the acquisition of oil and natural gas properties from Kerr-McGee. In August 2006, we entered into two interest rate swaps (as required by the Credit Agreement) to hedge the risk associated with the variable London Interbank Offered Rate ("LIBOR") used to reset the floating rates of our Tranche A and Tranche B term loans. For additional details about our derivatives, refer to Item 7A. "*Quantitative and Qualitative Disclosures About Market Risk*" and Note 8 to our consolidated financial statements.

Disruptions in the Capital Markets and Impact on Liquidity. Although there have been significant disruptions in the U.S. and global capital markets, the Company has not experienced any disruptions to its liquidity. The Company has historically been able to drill and develop properties and generate excess cash. We believe that our customers remain creditworthy and will continue to pay their bills as they become due. Our cash on hand at December 31, 2008 was $357.6 million and the undrawn capacity available under our revolving loan facility that matures in 2012 was $500.0 million. Availability under our credit facility is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their valuation of our proved reserves and their own internal criteria. On October 24, 2008, the lenders reaffirmed the borrowing base of our revolving loan facility and the undrawn amount of $500.0 million remains available for borrowing, subject to future periodic redeterminations of our borrowing base. Sixteen lenders participate in our revolving loan facility and we do not anticipate any of them being unable to satisfy their obligations under the Credit Agreement. As a result, we do not anticipate an immediate need for additional access to the capital markets. However, because of the significant issues currently facing the capital markets, it would be difficult to obtain debt or equity capital funding. We expect the next borrowing base redetermination to be finalized in April 2009 and we currently expect that such redetermination will result in a decrease in our borrowing base.

Insurance for damage from hurricanes in the Gulf of Mexico. During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. We maintain insurance coverage for named windstorms but we do not carry business interruption insurance. Our insurance policy has a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. The policy limits are $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities that will not be returned to production) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was well below our retention amount.

In the fourth quarter of 2008, two platforms (one operated and one non-operated) that were toppled by Hurricane Ike were deemed total losses having a combined insured value of approximately $15.8 million. After the application of the $10 million retention amount, we received net proceeds of $5.8 million. As of December 31, 2008, we have incurred $2.5 million and $17.3 million, net to our interest, to remediate damage caused by Hurricanes Gustav and Ike, respectively. Our insurance underwriters have approved $2.1 million of claims related to these expenditures, which is included in joint interest and other receivables at December 31, 2008. Substantially all of this amount was remitted to us in January 2009. The net amount of $17.7 million is included in lease operating expenses for the year ended December 31, 2008. Lease operating expenses will be offset in future periods to the extent that these expenses are recovered under our insurance policy. We have been providing information regarding our hurricane repair expenditures to our insurance adjuster for review. Following this review, our adjuster has been filing claims on our behalf with our insurance underwriters. The claims that have been processed in this manner have been paid on a timely basis. Additionally, as of December 31, 2008, we have increased our asset retirement obligations by approximately $37.0 million as a result of damage to our facilities caused by Hurricane Ike. To the extent that damages we may have incurred as a result of these hurricanes exceed our insurance coverage, we expect that our available cash and cash equivalents, cash flow from operations and the availability under our credit facility will be more than sufficient to meet any necessary expenditures.

Due to increased loss experience in recent years with hurricanes in the Gulf of Mexico and the turmoil in current financial markets, property damage and well control insurance coverage has become more limited and the cost of coverage has increased. Our insurers may not continue to offer the type and level of coverage currently available to us, or our costs may increase substantially as a result of increased premiums and the increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations.

In March 2007, we entered into agreements with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as a claim to recover drilling costs on a well at Green Canyon 82 that experienced uncontrollable water flow in the second quarter of 2006. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company received proceeds of $73.3 million in March 2007. Total reimbursements of $78.1 million received in the first quarter of 2007 exceeded our insurance receivables at December 31, 2006 by $2.9 million. Such amount was used to offset a portion of our hurricane remediation costs incurred in 2007, which totaled $25.2 million. In the third quarter of 2007, we recovered $3.8 million under the insurance policy of one of our partners, which also offset a portion of our hurricane remediation costs incurred in 2007. Included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for hurricane remediation expenses that were not covered by insurance.

Capital expenditures. The level of our investment in oil and gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities and the results of our exploration and development activities. For the year ended December 31, 2008, capital expenditures for oil and gas properties of $774.9 million included $116.6 million for the acquisition of Apache's interest in Ship Shoal 349 field, $337.6 million for exploration activities, $265.3 million for development activities and $55.4 million for seismic, capitalized interest and other leasehold costs. Our development and exploration capital expenditures consisted of $81.6 million in the deepwater, $48.8 million on the deep shelf and $472.5 million on the conventional shelf and other projects. Our capital expenditures for the year ended December 31, 2008 were financed by net cash from operating activities and cash on hand.

During 2008, we participated in the drilling of 24 gross exploratory wells and two gross development wells of which 21 were on the conventional shelf and five were on the deep shelf. Both of the development wells were successful and 18 of the exploratory wells were successful. We operate 12 of the 18 successful exploratory wells.

During 2007, our oil and gas investments totaled $361.2 million, including drilling seven gross exploratory wells and two gross development wells. During 2006, we invested approximately $1.7 billion in oil and gas properties, including the acquisition of interests in approximately 100 fields on 242 offshore blocks by merger in the Kerr-McGee transaction and the drilling of 26 gross exploratory wells and eight gross development wells. The wells we drilled over the past three years have tended to be deeper or were more technologically challenging than our past drilling projects and, consequently, have been more expensive to drill.

As a result of continued economic uncertainty, our drilling and capital expenditures in 2009 will be less than our drilling and capital expenditures in 2008. Our capital expenditure budget for 2009 is expected to approximate $220 million to $270 million and includes estimates for the completion of wells that were in progress at the end of 2008, wells or projects that we are presently committed to, lease saving operations, development wells where the rig is on location, scheduled recompletions and the development of our Green Canyon Block 646 prospect ("Daniel Boone"). We anticipate fully funding our 2009 capital expenditures with internally generated cash flow and cash on hand. Our capital expenditure budget does not include any amounts for potential acquisitions.

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 that are not expected to yield our historic return on equity when abandonment costs are considered.

Long-term debt. On July 24, 2008, we amended the Credit Agreement to extend the maturity of the revolving loan facility under the Credit Agreement to July 23, 2012 and increase the interest margin by 0.125% across the entire pricing grid for borrowings under the revolving loan facility. Certain other amendments were made to the Credit Agreement which changed or eliminated various covenants, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year.

Effective December 18, 2008 we amended the Credit Agreement further to allow us to repurchase up to $100.0 million (over the life of the Credit Agreement) of our common stock or the Notes in any allocation that we deem appropriate. No repurchases of either common stock or the Notes has occurred since the date of the amendment, as the Company currently does not have a stock or debt repurchase program in place. The December 18, 2008 amendment does not limit the dividend or share repurchase availability that was changed in connection with the amendment to the Credit Agreement on July 24, 2008. As consideration for the amendment we agreed to an increase in the interest margin by 0.25% across the entire pricing grid for borrowings under the revolving loan facility.

At December 31, 2008, our borrowing base under the Credit Agreement, as determined by our lenders, was $710.0 million. Such amount is sufficient to support the amount outstanding under the Tranche B term loan facility of $205.5 million (before unamortized discount) and the revolving loan facility of $500.0 million at December 31, 2008. Any determination by our lenders to reduce our borrowing base may cause a reduction in availability under our revolving loan facility. The Credit Agreement allows us to repay the Tranche B term loan facility with borrowings under the revolving loan facility and, subject to borrowing base limitations, to increase the size of the revolver to an amount not to exceed $710 million to the extent that the existing revolving lenders increase their respective commitments and/or additional lenders join the revolving loan facility, with aggregate commitments equal to such increased revolver.

Substantially all of our oil and gas properties are pledged as collateral under the Credit Agreement. In addition, the Credit Agreement contains covenants that restrict the payment of cash dividends, borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Further, we are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio, a minimum asset coverage ratio and a maximum leverage ratio, as such ratios are defined in the Credit Agreement. We were in compliance with all applicable covenants on December 31, 2008.

At December 31, 2008, we had no amounts outstanding on the revolving loan facility with $500.0 million of undrawn capacity. Also at December 31, 2008, borrowings outstanding on the Tranche B term loan facility totaled $203.2 million, net of unamortized discount of $2.3 million, of which $3.0 million is classified as current. Borrowings outstanding under the Notes were $450.0 million at December 31, 2008, all of which is classified as long-term. Even with projected decreases in cash flow from operations in 2009 as discussed above, we anticipate funding our scheduled debt payments with cash on hand and cash flow from operating activities. For additional details about our long-term debt, see Note 6 to our consolidated financial statements.

During the year ended December 31, 2008, we made principal payments of $3.0 million under our Credit Agreement. During the year ended December 31, 2007, we borrowed and repaid $458.0 million and $946.5 million, respectively, under our Credit Agreement and we issued $450.0 million of Notes. During the year ended December 31, 2006, we borrowed and repaid $1.1 billion and $485.5 million, respectively, under our Credit Agreement.

Asset retirement obligations. Each year the Company reviews and, to the extent necessary, revises its asset retirement obligation estimates. During 2007, we obtained new quotes and conducted a new study to evaluate the cost of decommissioning our properties. As a result, we increased our estimates of future asset retirement obligations to reflect recent costs incurred for plugging and abandonment activities in the Gulf of Mexico, where substantially all of our wells and production platforms are located. During 2008 we revised our estimate of the cost to decommission our sub-sea wells and made other changes to the estimated timing and amounts of settlements. In addition, we increased our estimated liabilities for decommissioning platforms that were damaged by Hurricane Ike.

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

Contractual obligations. The following summarizes our significant contractual obligations by maturity as of December 31, 2008. At December 31, 2008, we had no capital leases or long-term contracts for drilling rigs or equipment.

	Payments Due by Period at December 31, 2008				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years
			(Dollars in millions)		
Long-term debt – principal	$ 655.5	$ 3.0	$202.5	$ —	$450.0
Long-term debt – interest (1)	216.5	44.6	79.1	74.2	18.6
Drilling rigs	36.4	36.4	—	—	—
Operating leases	5.6	2.1	3.5	—	—
Asset retirement obligations	547.9	67.0	183.0	47.7	250.2
Derivatives	9.1	5.7	3.4	—	—
Other liabilities	2.4	—	2.4	—	—
	$1,473.4	$158.8	$473.9	$121.9	$718.8

(1) Includes interest on our Notes which bear interest at a fixed rate of 8.25% and our Tranche B term loan facility which is subject to a floating interest rate. The assumed interest rate on the aggregate outstanding principal balance of our Tranche B term loan facility ($205.5 million at December 31, 2008) is approximately 3.7% and is based on the three-month LIBOR rate at December 31, 2008 plus a margin equal to 2.25%. Interest was calculated through the stated maturity dates of the related debt.

Inflation and Seasonality

Inflation. While we have benefited from a general rise in the prices of oil and natural gas over the last three years, increased prices for drilling services, offshore transportation services and steel have impacted our lease operating expenses and our capital expenditures. Because of the significant decline in commodity prices that occurred in the latter part of 2008 along with a general economic downturn, we expect prices for the goods and services that we use in our operations to trend down in 2009. However, to the extent we drill wells in the deep water, the cost to drill such wells will be substantially more expensive than comparable wells on the conventional shelf.

Seasonality. Generally, the demand for and price of natural gas increases during the winter months and decreases 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 is also impacted by generally higher prices during winter months. Seasonal weather changes affect our operations. Tropical storms and hurricanes occur in the Gulf of Mexico during the summer and fall, which require us to evacuate personnel and shut-in production until these storms subside. Also, periodic storms during the winter often impede our ability to safely load, unload and transport personnel and equipment, which delays the installation of production facilities, thereby delaying sales of our oil and natural gas.

Critical Accounting Policies

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

Revenue recognition. We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties in which there is joint ownership. Under this method, we record oil and natural gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2008 and 2007, $7.0 million and $2.9 million, respectively, was included in current liabilities related to natural gas imbalances.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas properties are capitalized. Capitalization of geological and geophysical costs, certain employee costs and G&A costs related to these activities is permitted. We capitalize external geological and geophysical costs, which mainly consist of seismic costs. Total capitalized geological and geophysical costs on our balance sheets were approximately $88 million and $76 million at December 31, 2008 and 2007, respectively. We expensed approximately $4.7 million, $4.1 million and $4.3 million in geological and geophysical administrative costs during 2008, 2007 and 2006, respectively.

We amortize our investment in oil and natural gas properties, capitalized asset retirement obligations and future development costs (including asset retirement obligations of wells to be drilled) through DD&A, using the units of production method. The cost of unproved properties related to significant acquisitions are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are non-commercial. Total unproved properties excluded from amortization at December 31, 2008 and 2007 were $99.1 million and $278.9 million, respectively.

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We capitalized $19.3 million, $25.1 million and $13.2 million of interest expense during the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

Impairment of oil and natural gas properties. Under the full cost method of accounting, we are required to periodically perform a "ceiling test," which determines a limit on the book value of our oil and gas properties. If the net capitalized cost of oil and gas properties (including capitalized asset retirement obligations), net of related deferred income taxes, exceeds the present value of estimated future net revenues from proved reserves discounted at 10%, net of related tax effects, plus the cost of unproved oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. Any such write downs are not recoverable or reversible in future periods. Estimated future net revenues are based on period-end commodity prices and exclude future cash outflows related to capitalized asset retirement obligations and include future development costs and asset retirement obligations related to wells to be drilled. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion ($768.8 million after-tax). The further declines in oil and natural gas prices after December 31, 2008 may require us to record an additional ceiling test impairment in 2009. We did not have a ceiling test impairment during the years ended December 31, 2007 and 2006.

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 ("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 costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as the future prices of oil and natural gas; and
- the judgment of the persons preparing the estimates.

Our proved reserve information as of December 31, 2008 included in this annual report is based on estimates prepared by our independent petroleum consultant, Netherland, Sewell & Associates, Inc. Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made. Unless otherwise indicated, we deduct plugging and abandonment expenses in our calculation of PV-10 estimates. Approximately 68% of our total proved reserves at December 31, 2008 were classified as proved developed reserves, of which 38% are classified as non-producing. Most of our proved developed non-producing reserves are either "behind pipe" and will be produced after depletion of another horizon in the same well or are shut-in until the completion of repairs due to damage caused by Hurricanes Ike and Gustav. Approximately 35% of our proved undeveloped reserves have been booked within one year of the most recent reserve report and approximately 56% have been booked within two years of December 31, 2008. The remaining proved undeveloped reserves (booked more than two years ago) are all associated with wells that are either scheduled to be developed within the next three years or are waiting on a proved developed producing well to deplete in order to use the well bore to develop the target reserves.

Reporting of oil and gas production and reserves. We produce natural gas liquids as part of the processing of our natural gas. The extraction of natural gas liquids in the processing of natural gas reduces the volume of natural gas available for sale. In our December 31, 2008 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 4.7% of our total proved reserves. 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 2008 were approximately 43% lower on average than prices for equivalent volumes of oil and average prices are expected to be 34% 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.

The Company files annual estimates of certain proved oil and gas reserves with the U.S. Department of Energy (DOE) and the MMS, which are within 5% of the reserve estimates included in this annual report.

Asset retirement obligations. We have significant obligations to remove our platforms, pipelines, facilities and equipment and restore the land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells, removing pipelines, removing and disposing of offshore platforms and site clean up. 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 costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations, which can substantially affect our estimates of these future costs from period to period. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, we are required to record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

Inherent in the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free 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.

Fair value measurements. Effective January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements*, on a prospective basis. In February 2008, the FASB issued FASB Staff Position ("FSP") FAS 157-2, *Effective Date of FASB Statement No. 157*, which granted a one-year deferral of SFAS No. 157 for certain non-financial assets and liabilities.

At December 31, 2008, our interest rate swap was our only financial instrument to which SFAS No. 157 applied. In accordance with SFAS No. 157, we measure the fair value of our interest rate swap by applying the income approach, using inputs that are derived principally from observable market data. The impact of the adoption of SFAS No. 157 did not have a material impact on our financial statements.

Effective January 1, 2008, we adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115*. The adoption of SFAS No. 159 did not have an impact on our financial position, results of operations or cash flows as we elected not to measure any additional financial assets and liabilities at fair value that were not already required to be measured at fair value.

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. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of SFAS No. 109*, ("FIN 48"), effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense. The adoption of FIN 48 did not have an effect on our consolidated financial statements.

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

New Accounting Policies and Pronouncements

On December 29, 2008, the SEC adopted new rules related to modernizing accounting and disclosure requirements for oil and natural gas companies. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The new rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The new rules utilize a 12-month average price using beginning of the month pricing (January 1 to December 1) to report oil and gas reserves rather than year-end prices. In addition, the 12-month average will also be used to test cost center ceilings for impairment and to compute depreciation, depletion and amortization. The new rules are effective January 1, 2010 with first reporting for calendar year companies in their 2009 annual reports. Early adoption is not permitted. The Company is currently evaluating the impact of the new rules on its accounting and disclosure.

In June 2008, the FASB issued FSP No. Emerging Issues Task Force ("EITF") 03-6-1 ("FSP 03-6-1"), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* This FSP provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share under the two-class method described in Statement of Financial Accounting Standards ("SFAS") No. 128, *Earnings Per Share*. FSP 03-6-1 is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008, and will require all earnings per share data presented for prior-periods to be restated retrospectively. The application of FSP 03-6-1 will decrease our 2008 basic loss per share by $0.04 and will decrease our 2007 basic earnings per share by $0.01.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133, as amended; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. SFAS No. 161 will not have an impact on the Company's financial position, results of operations or cash flows upon adoption.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51*. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The statement is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS No. 160 will not have a material impact on the Company's financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007) ("SFAS No. 141(R)"), *Business Combinations*. SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree to be measured at their respective fair values at the acquisition date. Acquisition-related costs incurred prior to the acquisition are required to be expensed rather than included in the purchase-price determination. SFAS No. 141(R) also provides guidance for recognizing and measuring the goodwill acquired in a business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. We expect SFAS No. 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of acquisitions, if any, that we may consummate subsequent to the effective date of the new standard.

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. Currently, we are party to one interest rate swap contract with a financial institution and we do not have any open commodity derivatives. The Credit Agreement no longer requires us to maintain any commodity derivatives. We do not enter into derivative instruments for speculative trading purposes.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices for oil and natural gas, which fluctuate widely. Oil and natural gas price declines and volatility could adversely affect our revenues, net cash provided by operating activities and profitability. For example, assuming a 10% decline in our average realized oil and natural gas sales prices in 2008 and 2007, our loss before income taxes would have increased by approximately 15% in 2008 and our income before income taxes would have declined by approximately 52% in 2007. If costs and expenses of operating our properties had increased by 10% in 2008 and 2007, our loss before income taxes would have increased by approximately 3% in 2008 and our income before income taxes would have declined by approximately 12% in 2007.

Interest rate risk. As of December 31, 2008, we had $203.2 million of variable rate debt outstanding. 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 outstanding variable rate debt. Interest rate changes will impact future results of operations and cash flows. Assuming the same average borrowings on our Tranche B term loan facility and excluding the impact of our interest rate swap contract, a 100 basis point increase in interest rates would have increased our 2008 interest expense (before capitalized interest) by approximately $2.1 million. As of December 31, 2008, the carrying amount of our fixed rate debt was $450.0 million and the estimated fair value of such debt was $225.0 million.

The Credit Agreement initially required that we enter into interest rate hedging contracts with respect to at least 50% of the aggregate principal amount outstanding of our Tranche A and Tranche B term loan facilities. In August 2006, we entered into two interest rate swaps, which served to hedge the risk associated with the variable LIBOR used to reset the floating rates of our Tranche A and Tranche B term loan facilities. In June 2007, we amended the Credit Agreement to eliminate the requirement to maintain interest rate hedging contracts with respect to the Tranche A and Tranche B term loan facilities. Subsequently, we paid the Tranche A term loan facility in full and terminated the interest rate swap associated with the Tranche A term loan facility.

For the remaining interest rate swap associated with the Tranche B term loan facility, we pay the counterparty the equivalent of a fixed interest payment on 72% of the aggregate outstanding principal balance of the Tranche B term loan facility and receive from the counterparty the equivalent of a floating interest payment based on a 3-month LIBOR calculated on the same notional amount. All interest rate swap payments are made quarterly and the LIBOR is determined in advance of each interest period. In November 2007, a new counterparty assumed our interest rate swap through a novation and the fixed interest rate of the swap increased to 5.21% from 5.16%. As of December 31, 2008, the total notional amount of the swap was $147.8 million. The effective interest rate, including amortization of the discount, on the Tranche B term loan facility was 6.6% during the year ended December 31, 2008. For additional details about this derivative contract, refer to Note 8 to our consolidated financial statements.

Item 8. *Financial Statements and Supplementary Data*

W&T OFFSHORE, INC. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

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

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2008 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited W&T Offshore, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). W&T Offshore, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, W&T Offshore, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2008 consolidated financial statements of W&T Offshore, Inc. and subsidiaries and our report dated February 27, 2009, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income (loss), changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of W&T Offshore, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), W&T Offshore, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2009, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 27, 2009

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 357,552	$ 314,050
Receivables:		
Oil and natural gas sales	36,550	113,567
Joint interest and other	85,218	48,431
Income taxes	34,077	—
Total receivables	155,845	161,998
Prepaid expenses and other assets	30,417	43,645
Total current assets	543,814	519,693
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $99,139 at December 31, 2008 and $278,947 at December 31, 2007 were excluded from amortization)	4,684,730	3,805,208
Furniture, fixtures and other	14,370	10,267
Total property and equipment	4,699,100	3,815,475
Less accumulated depreciation, depletion and amortization	3,217,759	1,552,744
Net property and equipment	1,481,341	2,262,731
Restricted deposits for asset retirement obligations	24,138	23,718
Other assets	6,893	6,062
Total assets	$2,056,186	$2,812,204
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt	$ 3,000	$ 3,000
Accounts payable	228,899	159,973
Undistributed oil and natural gas proceeds	29,716	47,911
Asset retirement obligations – current portion	67,007	19,749
Accrued liabilities	18,254	65,328
Income taxes	—	12,975
Total current liabilities	346,876	308,936
Long-term debt, less current maturities – net of discount	650,172	651,764
Asset retirement obligations, less current portion	480,890	438,932
Deferred income taxes	—	255,097
Other liabilities	6,021	6,135
Commitments and contingencies		
Shareholders' equity:		
Common stock, $0.00001 par value; 118,330,000 shares authorized; issued and outstanding 76,291,408 and 76,175,159 shares at December 31, 2008 and December 31, 2007, respectively	1	1
Additional paid-in capital	372,595	365,667
Retained earnings	200,274	786,803
Accumulated other comprehensive loss	(643)	(1,131)
Total shareholders' equity	572,227	1,151,340
Total liabilities and shareholders' equity	$2,056,186	$2,812,204

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per share data)		
Revenues	$1,215,609	$1,113,749	$800,466
Operating costs and expenses:			
Lease operating expenses	229,747	234,758	113,993
Production taxes	8,827	5,921	1,556
Gathering and transportation	15,957	15,526	16,141
Depreciation, depletion and amortization	482,464	510,903	325,131
Asset retirement obligation accretion	39,312	22,007	12,496
Impairment of oil and natural gas properties	1,182,758	—	—
General and administrative expenses	47,225	38,853	37,778
Derivative loss (gain)	16,464	36,532	(24,244)
Total costs and expenses	2,022,754	864,500	482,851
Operating income (loss)	(807,145)	249,249	317,615
Interest expense:			
Incurred	54,001	62,188	30,418
Capitalized	(19,292)	(25,100)	(13,238)
Loss on extinguishment of debt	—	2,806	—
Other income	13,372	6,404	5,919
Income (loss) before income taxes	(828,482)	215,759	306,354
Income tax expense (benefit)	(269,663)	71,459	107,250
Net income (loss)	$ (558,819)	$ 144,300	$199,104
Earnings (loss) per common share:			
Basic	$ (7.36)	$ 1.90	$ 2.84
Diluted	(7.36)	1.90	2.84

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
	Shares	Value				
			(In thousands, except per share data)			
Balances at December 31, 2005	65,980	$ 1	$ 52,332	$ 491,050	$ —	$ 543,383
Cash dividends:						
Common stock ($0.12 per share)	—	—	—	(8,520)	—	(8,520)
Share-based compensation	—	—	2,544	—	—	2,544
Restricted stock issued, net of forfeitures	145	—	—	—	—	—
Common stock issued – equity offering	9,775	—	306,979	—	—	306,979
Net income	—	—	—	199,104	—	199,104
Other comprehensive loss, net of tax	—	—	—	—	(573)	(573)
Balances at December 31, 2006	75,900	1	361,855	681,634	(573)	1,042,917
Cash dividends:						
Common stock ($0.51 per share)	—	—	—	(39,131)	—	(39,131)
Share-based compensation	—	—	3,409	—	—	3,409
Restricted stock issued, net of forfeitures	336	—	2,229	—	—	2,229
Shares surrendered for payroll taxes	(61)	—	(1,826)	—	—	(1,826)
Net income	—	—	—	144,300	—	144,300
Other comprehensive loss, net of tax	—	—	—	—	(558)	(558)
Balances at December 31, 2007	76,175	1	365,667	786,803	(1,131)	1,151,340
Cash dividends:						
Common stock ($0.36 per share)	—	—	—	(27,710)	—	(27,710)
Share-based compensation	—	—	6,029	—	—	6,029
Restricted stock issued, net of forfeitures	178	—	1,731	—	—	1,731
Shares surrendered for payroll taxes	(62)	—	(832)	—	—	(832)
Net loss	—	—	—	(558,819)	—	(558,819)
Other comprehensive income, net of tax	—	—	—	—	488	488
Balances at December 31, 2008	76,291	$ 1	$372,595	$ 200,274	$ (643)	$ 572,227

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Operating activities:			
Net income (loss)	$ (558,819)	$ 144,300	$ 199,104
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	521,776	532,910	337,627
Impairment of oil and natural gas properties	1,182,758	—	—
Amortization of debt issuance costs and discount on indebtedness	2,749	6,472	8,182
Loss on extinguishment of debt	—	2,806	—
Share-based compensation related to restricted stock issuances	6,029	3,409	2,544
Unrealized derivative (gain) loss	(13,501)	37,831	(13,476)
Deferred income taxes	(249,445)	8,751	106,645
Other	833	1,006	511
Changes in operating assets and liabilities:			
Oil and natural gas receivables	77,017	(15,205)	(54,470)
Joint interest and other receivables	(35,885)	(22,356)	(9,646)
Insurance receivables	—	75,151	(61,301)
Income taxes	(46,930)	28,579	(47,313)
Prepaid expenses and other assets	4,917	477	(27,168)
Asset retirement obligations	(61,213)	(39,267)	(24,492)
Accounts payable and accrued liabilities	52,210	(76,199)	154,336
Other liabilities	—	(68)	506
Net cash provided by operating activities	882,496	688,597	571,589
Investing activities:			
Acquisition of property interests	(116,551)	—	(1,061,769)
Investment in oil and natural gas properties and equipment, net	(658,328)	(359,376)	(588,978)
Proceeds from insurance	5,828	—	—
Purchases of furniture, fixtures and other, net	(4,812)	(711)	(5,156)
Net cash used in investing activities	(773,863)	(360,087)	(1,655,903)
Financing activities:			
Issuance of Senior Notes	—	450,000	—
Borrowings of other long-term debt	—	458,000	1,123,732
Repayments of long-term debt	(3,000)	(946,500)	(485,500)
Proceeds from equity offering, net of costs	—	—	306,979
Dividends to shareholders	(59,999)	(9,137)	(8,225)
Debt issuance costs and other	(2,132)	(6,058)	(1,135)
Net cash (used in) provided by financing activities	(65,131)	(53,695)	935,851
Increase (decrease) in cash and cash equivalents	43,502	274,815	(148,463)
Cash and cash equivalents, beginning of period	314,050	39,235	187,698
Cash and cash equivalents, end of period	$ 357,552	$ 314,050	$ 39,235

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, referred to herein as "W&T" or the "Company," is an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties in the Gulf of Mexico.

Basis of Presentation

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

Reclassifications

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

Use of Estimates

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

Cash Equivalents

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

Revenue Recognition

We recognize oil and gas revenues based on the quantities of our production sold to purchasers under short-term contracts (less than 12 months) at market prices when delivery has occurred, title has transferred and collectiblity is reasonably assured. We use the sales method of accounting for oil and gas revenues from properties in which there is joint ownership. Under this method, we record oil and gas revenues based upon physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which the Company has taken less than its ownership share of production. At December 31, 2008 and 2007, $7.0 million and $2.9 million, respectively, was included in current liabilities related to natural gas imbalances.

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. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures, and letters of credit or guaranties when considered necessary. We historically have not had any significant problems collecting our receivables, except in rare circumstances. Accordingly, we do not maintain an allowance for doubtful accounts.

The following identifies customers from whom we derived 10% or more of receipts from sales of oil and natural gas.

	Year Ended December 31,		
	2008	2007	2006
Customer			
Shell Trading (US) Company	33%	31%	28%
Chevron	19%	11%	**
ConocoPhillips	**	17%	14%
BP	**	**	10%

** less than 10%

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

Oil and Gas Properties and Equipment

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

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

We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized only for the period that exploration and development activities are in progress. We capitalized $19.3 million, $25.1 million and $13.2 million of interest expense during the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

Under the full cost method of accounting, we are required to periodically perform a "ceiling test," which determines a limit on the book value of our oil and gas properties. If the net capitalized cost of oil and gas properties (including capitalized asset retirement obligations), net of related deferred income taxes, exceeds the present value of estimated future net revenues from proved reserves discounted at 10%, net of related tax effects, plus the cost of unproved oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. Any such write downs are not recoverable or reversible in future periods. Estimated future net revenues are based on period-end commodity prices and exclude future cash outflows related to capitalized asset retirement obligations and include future development costs and asset retirement obligations related to wells to be drilled. Primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008, we recorded a ceiling test impairment at December 31, 2008 of $1.2 billion ($768.8 million after-tax). The further declines in oil and natural gas prices after December 31, 2008 may require us to record an additional ceiling test impairment in 2009. We did not have a ceiling test impairment during the years ended December 31, 2007 and 2006.

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

Derivative Financial Instruments

Our market risk exposure relates primarily to commodity prices and interest rates. We use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our credit facility. Currently, we are party to one interest rate swap contract with a financial institution and we do not have any open commodity derivatives. We do not enter into derivative instruments for speculative trading purposes.

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

During the years ended December 31, 2008, 2007 and 2006, changes in the fair value of our commodity derivative contracts were recognized currently in earnings. In 2006, our interest rate swaps qualified as cash flow hedges under SFAS No. 133 and, therefore, unrealized gains and losses related to changes in the fair value of our interest rate swaps were deferred in other comprehensive income and realized gains and losses were recognized in interest expense when the forecasted transaction occurred. In 2007, we terminated one of our interest rate swap contracts and de-designated the remaining interest rate swap contract as a cash flow hedge. From the dates of de-designation, subsequent changes in the fair value of our interest rate swap were immediately recognized in earnings.

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 and accrued liabilities materially approximates fair value due to the short-term nature and the terms of these instruments.

Effective January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements*, on a prospective basis. In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS 157-2, *Effective Date of FASB Statement No. 157*, which granted a one-year deferral of SFAS No. 157 for certain non-financial assets and liabilities. We do not expect SFAS No. 157 to have a material impact on our non-financial assets and liabilities.

At December 31, 2008, our interest rate swap was our only financial instrument to which SFAS No. 157 applied. In accordance with SFAS No. 157, we measure the fair value of our interest rate swap by applying the income approach, using inputs that are derived principally from observable market data. The impact of the adoption of SFAS No. 157 did not have a material impact on our financial statements.

Effective January 1, 2008, we adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115*. The adoption of SFAS No. 159 did not have an impact on our financial position, results of operations or cash flows as we elected not to measure any additional financial assets and liabilities at fair value that were not already required to be measured at fair value.

Income Taxes

We use the liability method of accounting for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized.

Deferred Financing Costs

Debt issuance costs associated with our revolving loan facility are amortized using the straight-line method over the scheduled maturity of the debt. Debt issuance costs and debt premiums or discounts associated with all other debt are deferred and amortized over the scheduled maturity of the debt utilizing the effective interest method.

Share-Based Compensation

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

Earnings (Loss) Per Share

Basic earnings (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings (loss) per share incorporates the potential dilutive impact of nonvested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive.

Recent Accounting Developments

On December 29, 2008, the Securities and Exchange Commission ("SEC") adopted new rules related to modernizing accounting and disclosure requirements for oil and natural gas companies. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The new rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The new rules utilize a 12-month average price using beginning of the month pricing (January 1 to December 1) to report oil and gas reserves rather than year-end prices. In addition, the 12-month average will also be used to test cost center ceilings for impairment and to compute depreciation, depletion and amortization. The new rules are effective January 1, 2010 with first reporting for calendar year companies in their 2009 annual reports. Early adoption is not permitted. The Company is currently evaluating the impact of the new rules on its accounting and disclosure.

In June 2008, the FASB issued FSP No. Emerging Issues Task Force ("EITF") 03-6-1 ("FSP 03-6-1"), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* This FSP provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share under the two-class method described in SFAS No. 128, *Earnings Per Share.* FSP 03-6-1 is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008, and will require all earnings per share data presented for prior-periods to be restated retrospectively. The application of FSP 03-6-1 will decrease our 2008 basic loss per share by $0.04 and will decrease our 2007 basic earnings per share by $0.01.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133.* SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133, as amended; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. SFAS No. 161 will not have an impact on the Company's financial position, results of operations or cash flows upon adoption.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51.* SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The statement is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS No. 160 will not have a material impact on the Company's financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007) ("SFAS No. 141(R)"), *Business Combinations.* SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree to be measured at their respective fair values at the acquisition date. Acquisition-related costs incurred prior to the acquisition are required to be expensed rather than included in the purchase-price determination. SFAS No. 141(R) also provides guidance for recognizing and measuring the goodwill acquired in a business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. We expect SFAS No. 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of acquisitions, if any, that we may consummate subsequent to the effective date of the new standard.

2. Asset Retirement Obligations

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

The following is a reconciliation of our asset retirement obligation liability as of December 31, 2008 and 2007 (in millions).

	2008	2007
Asset retirement obligation, beginning of period	$458.7	$314.1
Liabilities settled	(61.2)	(39.3)
Accretion of discount	39.3	22.0
Liabilities assumed through acquisition	2.6	3.1
Liabilities incurred, net of sales	2.3	1.0
Revisions of estimated liabilities (1)	106.2	157.8
Asset retirement obligation, end of period	547.9	458.7
Less current portion	67.0	19.8
Long-term	$480.9	$438.9

(1) Each year the Company reviews and, to the extent necessary, revises its asset retirement obligation estimates. During 2007, we obtained new quotes and conducted a new study to evaluate the cost of decommissioning our properties. As a result, we increased our estimates of future asset retirement obligations by $157.8 million to reflect recent costs incurred for plugging and abandonment activities in the Gulf of Mexico, where substantially all of our wells and production platforms are located. During 2008, the Company revised, among other things, its estimate of the cost to decommission its sub-sea wells and made other changes to the estimated timing and amounts of settlements. Also included in our revisions of estimated liabilities for 2008 is an approximate $37.0 million increase in estimated settlements as a result of damage to our facilities caused by Hurricane Ike in the third quarter of 2008.

3. Restricted Deposits

Restricted deposits as of December 31, 2008 and 2007 consisted of funds escrowed for the future plugging and abandonment of certain oil and gas properties. We are not obligated to contribute additional amounts to these escrowed accounts.

4. Significant Acquisitions

Kerr-McGee Transaction

On August 24, 2006, we closed the acquisition of a wholly-owned subsidiary of Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger. The properties acquired included interests in approximately 100 fields on 242 offshore blocks (including 88 undeveloped blocks) spreading across the Western, Central and Eastern Gulf of Mexico, primarily in water depths of less than 1,000 feet. This transaction was financed through a combination of cash on hand, bank financing and proceeds from a public offering of our common stock.

This acquisition was accounted for as a purchase and, accordingly, the results of operations are included in our consolidated statements of income from the date of acquisition. The purchase price was allocated to the acquired assets and assumed liabilities based on their estimated fair values at the date of acquisition. The following summarizes the estimated fair values of assets acquired and liabilities assumed at closing (in thousands):

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

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

	Year Ended December 31, 2006	
	Historical	Pro Forma (Unaudited)
Revenues	$800,466	$1,147,455
Net income	199,104	278,366
Earnings per share:		
Basic	$ 2.84	$ 3.67
Diluted	2.84	3.67

Acquisition of Remaining Interest in Ship Shoal 349 Field

On December 21, 2007, we entered into an agreement with Apache Corporation ("Apache") to acquire its interest in Ship Shoal 349 field for $116.6 million in cash. This field is located off the coast of Louisiana and covers two federal offshore lease blocks, Ship Shoal blocks 349 and 359. The transaction closed on January 29, 2008, with an effective date of January 1, 2008. The acquisition increased our working interest in this field to 100% from approximately 59%, and the estimated proved oil and gas reserves acquired were 60.5 Bcfe. A deposit of $5.8 million related to this acquisition is included in prepaid expenses and other assets at December 31, 2007. This acquisition was funded from cash on hand.

5. Equity Structure and Transactions

As of December 31, 2008 and 2007, the Company was authorized to issue two million shares of preferred stock with a par value of $0.00001 per share; however, no preferred shares have been issued or were outstanding as of the respective dates.

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

On January 11, 2008 we paid a special cash dividend of $30.0 million, or approximately $0.39 per common share, to shareholders of record on December 21, 2007. On December 22, 2008, we paid a special cash dividend of $20.84 million, or approximately $0.2729 per common share, to shareholders of record on December 1, 2008. We amended our Third Amended and Restated Credit Agreement, as amended (the "Credit Agreement") to allow for such special dividends (see Note 6). Also during the three years ended December 31, 2008, we paid regular cash dividends of $0.12 per common share per year. Included in accrued liabilities at December 31, 2007 is $32.3 million for dividends declared but unpaid as of that date. On February 25, 2009, our board of directors declared a cash dividend of $0.03 per common share, payable on March 20, 2009 to shareholders of record on March 6, 2009.

6. Long-Term Debt

As of December 31, 2008 and 2007 our long-term debt was as follows (in thousands):

	December 31,	
	2008	2007
Revolving loan facility, due July 2012	$ —	$ —
Tranche B term loan facility, net of unamortized discount of $2,328 at December 31, 2008 and $3,736 at December 31, 2007, due August 2010	203,172	204,764
8.25% Senior notes, due June 2014	450,000	450,000
Total long-term debt	653,172	654,764
Current maturities of long-term debt	(3,000)	(3,000)
Long-term debt, less current maturities	$650,172	$651,764

At December 31, 2008, the estimated fair value of our Senior notes was approximately $225 million and the estimated fair value of our Tranche B term loan facility was approximately $186 million.

Aggregate annual maturities of long-term debt as of December 31, 2008 are as follows (in millions): 2009–$3.0; 2010–$202.5; 2011–$0.0; 2012–$0.0; 2013–$0.0; thereafter–$450.0.

Private Offering of 8.25% Senior Notes due 2014

In June 2007, the Company sold and issued to eligible investors $450.0 million aggregate principal amount of 8.25% senior notes due 2014 (the "Notes") pursuant to Rule 144A under the Securities Act of 1933, as amended. Net proceeds generated by the offering were approximately $444.6 million after underwriting fees of $4.1 million and legal, accounting, printing and various other fees of approximately $1.3 million. The Company used substantially all of the net proceeds from the private placement of the Notes to repay a portion of the outstanding borrowings under the Credit Agreement.

The Notes bear interest at a fixed rate of 8.25%, with interest payable semi-annually in arrears on June 15 and December 15. The estimated annual effective interest rate on the Notes is 8.4%.

The Company and its restricted subsidiaries are subject to certain covenants under the indenture governing the Notes which limit the Company's and each of its restricted subsidiaries' ability to, among other things, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of its assets, engage in transactions with affiliates, pay dividends or make other distributions on capital stock or subordinated indebtedness and create unrestricted subsidiaries.

Credit Agreement

The Credit Agreement was amended in June 2007 whereby the amount of senior unsecured indebtedness the Company may incur was increased to $500.0 million to allow for the issuance of the Notes, provided that the proceeds from the Notes would be used to prepay the Tranche A term loan facility in full. Consequently, in June 2007, the Company paid in full the Tranche A term loan facility outstanding balance of $50.0 million plus accrued and unpaid interest of $0.2 million. The Company also used proceeds from the Notes to make a payment of $90.0 million on the Tranche B term loan facility balance outstanding plus accrued and unpaid interest of $1.5 million and to pay the revolving loan facility balance then outstanding of $271.0 million. During the year ended December 31, 2007, we recorded a loss of $2.8 million related to the write-off of all the deferred financing costs related to the Tranche A term loan facility and a pro-rata portion of the deferred financing costs related to the Tranche B term loan facility. On November 6, 2007, the Credit Agreement was amended to provide for, among other things, an increase in the capacity available under our revolving loan facility to $500.0 million from $300.0 million and to allow for a special dividend of up to $30.0 million, to be declared before the end of 2007.

On July 24, 2008, we amended the Credit Agreement to extend the maturity of our committed revolving loan facility under the Credit Agreement to July 23, 2012 and increase the interest margin by 0.125% across the entire pricing grid for borrowings under the revolving loan facility. Certain other amendments were made to the Credit Agreement which changed or eliminated various covenants, including increasing the annual amount available for dividend distribution or share repurchases to $60.0 million per year from $30.0 million per year.

Effective December 18, 2008, the Credit Agreement was further amended to increase the interest margin by 0.25% across the entire pricing grid for borrowings under the revolving loan facility. Other amendments were made to the Credit Agreement which modified certain covenants, including allowing for the repurchase of our common stock and/or Notes in an aggregate amount not to exceed $100.0 million (over the life of the Credit Agreement). No repurchases of either common stock or the Notes has occurred since the date of the amendment, as the Company currently does not have a stock or debt repurchase program in place. The December 18, 2008 amendment does not limit the dividend or share repurchase availability that was changed in connection with the amendment to the Credit Agreement on July 24, 2008.

Effective December 18, 2008, borrowings under the revolving loan facility bear interest at either (1) the higher of the Prime Rate, or the Federal Funds Rate plus 0.50%, plus a margin which varies from 0.375% to

1.0% depending on the level of total borrowings under the Credit Agreement or (2) to the extent the loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate ("LIBOR") plus a margin that varies from 1.625% to 2.25% depending on the level of total borrowings under the Credit Agreement. The Credit Agreement also bears an unused commitment fee that ranges from 0.30% to 0.50% depending on the level of total borrowings outstanding under the revolving loan facility. During the year ended December 31, 2008, we did not have any borrowings or repayments under the revolving loan facility.

Borrowings under the Tranche B term loan facility bear interest at either (1) the higher of the Prime Rate, or the Federal Funds Rate plus 0.50%, plus a margin equal to 1.25% or (2) to the extent the loan outstanding is designated as a Eurodollar loan, at the LIBOR plus a margin equal to 2.25%. The effective interest rate, including amortization of the discount, on the Tranche B term loan facility was 6.6% during the year ended December 31, 2008.

The Credit Agreement is a secured facility that is collateralized by our oil and gas properties. Availability under our credit facility is subject to a semi-annual borrowing base redetermination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their valuation of our proved reserves and their own internal criteria. On October 24, 2008, the lenders reaffirmed the borrowing base of our revolving loan facility and the undrawn amount of $500.0 million remains available for borrowing, subject to future periodic redeterminations of our borrowing base. At December 31, 2008, we had $500.0 million of undrawn capacity available under our revolving loan facility. The Credit Agreement provides for the availability of letters of credit for up to $90.0 million, provided however, that its usage is subject to availability under the revolving loan. At December 31, 2008, we had a letter of credit outstanding totaling $0.2 million and at December 31, 2007 we did not have any letters of credit outstanding.

At December 31, 2008, our borrowing base under the Credit Agreement, as determined by our lenders, was $710.0 million. Such amount is sufficient to support the amount outstanding under the Tranche B term loan facility of $205.5 million (before unamortized discount) and the revolving loan facility of $500.0 million at December 31, 2008. Any determination by our lenders to reduce our borrowing base may cause a reduction in availability under our revolving loan facility. The Credit Agreement allows us to repay the Tranche B term loan facility with borrowings under the revolving loan facility and, subject to borrowing base limitations, to increase the size of the revolver to an amount not to exceed $710 million to the extent that the existing revolving lenders increase their respective commitments and/or additional lenders join the revolving loan facility, with aggregate commitments equal to such increased revolver.

The Credit Agreement contains covenants that restrict the payment of cash dividends and share repurchases, borrowings other than from the facilities, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a current ratio, asset coverage ratio and a leverage ratio. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2008.

7. Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, *Fair Value Measurements*, on a prospective basis. SFAS No. 157 establishes a framework for measuring fair value under GAAP, clarifies the definition of fair value within that framework, and expands disclosures about the use of fair value measurements. This statement applies to all existing pronouncements under GAAP that require (or permit) the use of fair value, with the exception of SFAS No. 123(R), *Share-Based Payment*. SFAS No. 157 does not require any new fair value measurements under GAAP. In February 2008, the FASB issued FSP FAS 157-2, *Effective Date of FASB Statement No. 157*, which granted a one-year deferral of SFAS No. 157 for certain non-financial assets and liabilities. Accordingly, our asset retirement obligations incurred during the year ended December 31, 2008 were initially measured at fair value in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. Effective January 1, 2009, our asset retirement obligations incurred will be initially measured at fair value in accordance with SFAS No. 157. We do not expect that initial measurements of our asset retirement obligations at fair value under SFAS No. 157 will be materially different from initial measurements of our asset retirement obligations at fair value under SFAS No. 143.

Under SFAS No. 157, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether using an in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company's credit risk.

Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of these techniques requires significant judgment and is primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
- Level 3 – unobservable inputs that reflect the Company's own expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

At December 31, 2008, the only item on our balance sheet to which SFAS No. 157 applied was our interest rate swap. We measure the fair value of our interest rate swap by applying the income approach and our swap is classified within level 2 of the valuation hierarchy. The fair value of our interest rate swap liability was $9.1 million at December 31, 2008. The impact of the adoption of SFAS No. 157 on our financial position and results of operations was immaterial. For additional details about our derivatives, refer to Note 8.

8. Derivative Financial Instruments

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

Commodity Derivatives

As of December 31, 2008, we did not have any open commodity derivative positions. As of December 31, 2007, our open commodity derivatives were as follows:

Collars

Type	Commodity	Effective Date	Termination Date	Notional Quantity	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling	Fair Value Asset (Liability) (in thousands)
Funded	Natural Gas	2/1/2008	12/31/2008	4,690,000 MMBtu	$ 7.31	$15.80	$ 2,224
Zero Cost	Oil	1/1/2008	12/31/2008	1,024,800 Bbls	60.00	74.50	(19,599)
							$(17,375)

At December 31, 2007, $2.2 million was included in prepaid expenses and other assets and $19.6 million was included in accrued liabilities related to our open commodity derivatives.

During the year ended December 31, 2008, we recorded a realized loss of $27.4 million related to settlements of our commodity derivative contracts offset by a change in the fair value of our commodity derivative contracts of $17.4 million. In 2007 and 2006, we recorded realized gains of $1.3 million and $10.7 million, respectively, and we recorded an unrealized loss of $34.3 million and an unrealized gain of $13.5 million, respectively, related to our commodity derivatives.

Interest Rate Swap

In June 2007, we paid our Tranche A term loan facility in full and terminated the interest rate swap associated with the Tranche A term loan facility. Also in June 2007, we made a payment of $90.0 million on the outstanding balance of the Tranche B term loan facility and de-designated as a cash flow hedge 30% of the notional amount of the interest rate swap associated with the Tranche B term loan facility. As of the date of de-designation (June 14, 2007), the fair value of the de-designated portion of the swap was approximately $0.3 million (net of income tax), which was recorded in accumulated other comprehensive income and is being recognized in earnings through interest expense over the remaining term of the interest rate swap. In connection with an amendment to the Credit Agreement in November 2007 to increase the capacity available under our revolving loan facility (see Note 6), a new counterparty assumed our interest rate swap through a novation and the fixed interest rate of the swap increased to 5.21% from 5.16%. As of the date of the novation (November 6, 2007), the remaining 70% of the notional amount of our interest rate swap no longer qualified as a cash flow hedge under SFAS No. 133. On November 6, 2007, the fair value of 70% of the notional amount of our interest rate swap was approximately $1.4 million (net of income tax), which was recorded in accumulated other comprehensive income and is being recognized in earnings through interest expense over the remaining term of the interest rate swap. From the respective dates of de-designation, subsequent changes in the fair value of these portions of our interest rate swap were immediately recognized in earnings in 2007.

During the year ended December 31, 2008, we recorded realized and unrealized losses of $2.6 million and $3.9 million, respectively, related to our interest rate swap. During the year ended December 31, 2007, we recorded an unrealized loss of $3.5 million related to our interest rate swap. The realized gain on our interest rate swap during the year ended December 31, 2007 was not material. For the years ended December 31, 2007 and 2006, no amount was recognized in earnings due to ineffectiveness related to our interest rate swap.

At December 31, 2008, $5.7 million was included in accrued liabilities and $3.4 million was included in other liabilities related to our interest rate swap, representing the current and non-current portions, respectively.

At December 31, 2007, $1.7 million was included in accrued liabilities and $3.4 million was included in other liabilities related to our interest rate swap.

9. Income Taxes

FIN 48

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of SFAS No. 109*, ("FIN 48"), effective January 1, 2007. The adoption of FIN 48 did not have an effect on our consolidated financial statements.

As of December 31, 2008, we do not have any accrued interest or penalties related to uncertain tax positions; however, when applicable, we will recognize interest and penalties related to uncertain tax positions in income tax expense. We do not have any unrecognized tax benefits as of December 31, 2008. The tax years from 2004 through 2008 remain open to examination by the tax jurisdictions to which we are subject.

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2008	2007	2006
Current federal	$ (20,356)	$62,708	$ 605
Current state	138	—	—
Deferred federal	(249,445)	8,751	106,645
	$(269,663)	$71,459	$107,250

Effective Tax Rate Reconciliation

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

	Year Ended December 31,					
	2008		2007		2006	
Income tax expense (benefit) at the federal statutory rate	$(289,969)	35.0%	$75,516	35.0%	$107,224	35.0%
Share-based compensation	1,214	(0.2)	—	—	—	—
Domestic production activities deduction	1,048	(0.2)	(4,116)	(1.9)	—	—
State income taxes	138	—	—	—	—	—
Other	515	—	59	—	26	—
Valuation allowance	17,391	(2.1)	—	—	—	—
	$(269,663)	32.5%	$71,459	33.1%	$107,250	35.0%

Our effective tax rate for the year ended December 31, 2008 primarily reflects the effect of a valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2007 reflects the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code. In 2008 and 2006, the Company experienced a net operating loss for tax purposes and as a result, the qualified domestic production activities deduction was not available to us. Additionally, in 2008 a portion of the qualified domestic production activities deduction for 2007 was recaptured due to a carryback of the net operating loss in 2008 to 2007.

Deferred Tax Assets and Liabilities

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, 2008	December 31, 2007
Deferred tax liabilities:		
Property and equipment	$ —	$256,403
Other	3,598	4,543
Total deferred tax liabilities	3,598	260,946
Deferred tax assets:		
Derivatives	2,930	9,133
State net operating loss	2,627	2,337
Property and equipment	13,846	—
Other	4,213	2,631
Valuation allowance	(20,018)	(2,337)
Total deferred tax assets	3,598	11,764
Net deferred tax liabilities	$ —	$249,182

During the year ended December 31, 2008, we recorded a ceiling test impairment of $1.2 billion ($768.8 million after-tax), which resulted in a deferred tax asset balance related to our oil and gas properties and equipment. This balance was fully offset by a valuation allowance. At December 31, 2008, we had a federal income tax receivable of $34.1 million. This amount is comprised of estimated federal tax payments deposited in 2008 of $17.7 million and a net operating loss carryback to 2007 of $16.4 million. Included in prepaid expenses and other assets at December 31, 2007 is approximately $5.9 million related to the current portion of deferred tax assets.

Net Operating Loss and Tax Carryovers

The table below presents the details of our state net operating loss carryover periods as of December 31, 2008 (in thousands):

	Amount	Expiration Year
State net operating loss	$50,511	2021-2024

Valuation Allowance

Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As part of our assessment, we consider future reversals of existing taxable temporary differences. A valuation allowance offsets substantially all of our deferred tax assets at December 31, 2008.

10. Commitments

We have operating lease agreements for office space and office equipment, which terminate in January 2012. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2008 are as follows (in millions): 2009–$2.1; 2010–$1.8; 2011–$1.7; 2012–$0.0; 2013–$0.0; thereafter–$0.0.

Total rent expense was approximately $2.1 million, $2.5 million and $1.4 million during the years ended December 31, 2008, 2007 and 2006, respectively.

11. Contingent Liabilities

We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. Some of these claims relate to matters occurring prior to our acquisition of properties and some relate to properties we have sold. In certain cases, we are entitled to indemnification from the sellers of properties and in other cases, we have indemnified the buyers to whom we have sold properties. Although we can give no assurance about the outcome of pending legal and administrative proceedings and the effect such an outcome may have on us, 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 our consolidated financial position, results of operations or liquidity.

12. Tropical Weather

During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. We maintain insurance coverage for named windstorms but we do not carry business interruption insurance. Our insurance policy has a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. The policy limits are $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities that will not be returned to production) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was well below our retention amount.

In the fourth quarter of 2008, two platforms (one operated and one non-operated) that were toppled by Hurricane Ike were deemed total losses having a combined insured value of approximately $15.8 million. After the application of the $10 million retention amount, we received net proceeds of $5.8 million. As of December 31, 2008, we have incurred $2.5 million and $17.3 million, net to our interest, to remediate damage caused by Hurricanes Gustav and Ike, respectively. Our insurance underwriters have approved $2.1 million of claims related to these expenditures, which is included in joint interest and other receivables at December 31, 2008. Substantially all of this amount was remitted to us in January 2009. The net amount of $17.7 million is included in lease operating expenses for the year ended December 31, 2008. Lease operating expenses will be offset in future periods to the extent that these expenses are recovered under our insurance policy. We have been providing information regarding our hurricane repair expenditures to our insurance adjuster for review. Following this review, our adjuster has been filing claims on our behalf with our insurance underwriters. The claims that have been processed in this manner have been paid on a timely basis. Additionally, as of December 31, 2008, we have increased our asset retirement obligations by approximately $37.0 million as a result of damage to our facilities caused by Hurricane Ike (see Note 2). To the extent that damages we may have incurred as a result of these hurricanes exceed our insurance coverage, we expect that our available cash and cash equivalents, cash flow from operations and the availability under our credit facility will be more than sufficient to meet any necessary expenditures.

In March 2007, we entered into agreements with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita, as well as a claim to recover drilling costs on a well at Green Canyon 82 that experienced uncontrollable water flow in the second quarter of 2006. After adjustments for applicable deductibles and reimbursements of $21.9 million received in 2006 and $4.8 million received in February 2007, the Company received proceeds of $73.3 million in March 2007. Total reimbursements of $78.1 million received in the first quarter of 2007 exceeded our insurance receivables at December 31, 2006 by $2.9 million. Such amount was used to offset a portion of our hurricane remediation costs incurred in 2007, which totaled $25.2 million. In the third quarter of 2007, we recovered $3.8 million under the insurance policy of one of our partners, which also offset a portion of our hurricane remediation costs incurred in 2007. Included in lease operating expenses for the year ended December 31, 2007 is $18.5 million for hurricane remediation expenses that were not covered by insurance.

13. Long-Term Incentive Compensation

The Company maintains a long-term incentive compensation plan (the "Compensation 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 reserve growth, production growth, lease operating cost containment and general and administrative cost containment. The Compensation Plan may be terminated by executive management or the board of directors at any time without incurring additional obligations for grants.

As part of the Compensation Plan, the Company has an Annual Incentive Plan (as amended, the "Plan") that covers all employees of the Company except those executive officers who, by written agreement, have elected not to participate (our Chief Executive Officer and our Secretary). Under the Plan, eligible employees earn cash bonuses and awards of restricted stock from a bonus pool. The bonus pool consists of five percent of pre-tax income, which may be adjusted for extraordinary or unusual items or events (such as a ceiling test impairment), as determined by the Compensation Committee of the board of directors in its sole discretion. Awards of restricted stock are issued pursuant to, and are subject to, the terms of the Plan.

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

2007 Bonus

In February 2008, our board of directors approved payment of a general bonus for 2007 in accordance with the Plan, consisting of cash and restricted stock.

Cash bonuses for 2007 were paid in March 2008 and totaled $4.5 million, of which $3.5 million was expensed in 2007, $0.6 million was expensed in the first quarter of 2008 and the remainder was billed to partners under joint operating agreements.

The restricted stock portion of the 2007 bonus was settled in March 2008 by the granting and issuing of 196,112 restricted shares of our common stock with a fair value of approximately $6.3 million. The associated compensation expense, less an allowance for estimated forfeitures, is being recognized over the requisite service period of four years beginning on the first day of the bonus year. Accrued liability amounts of approximately $1.6 million ($1.4 million at December 31, 2007) related to the recognition of compensation expense during the service period prior to the issuance of the restricted shares were reclassified to additional paid-in capital upon issuance of the restricted shares in March 2008 (see Note 14).

2008 Bonus

In accordance with the Plan, the Compensation Committee and the Board of Directors have determined that the bonus pool for 2008 shall equal the amount necessary to pay 100% of the general bonus to all eligible employees and the Compensation Committee and the Board of Directors have authorized payment of 100% of such general bonus for 2008. Accordingly, eligible employees will be entitled to receive a general bonus for 2008 in accordance with the Plan, consisting of cash and restricted stock. Shares of restricted stock to be awarded as a bonus for 2008 will be issued in 2009 and have a four year requisite service period beginning January 1, 2008 and will vest in three equal installments in December 2009, 2010 and 2011. The cash bonus for 2008 will be paid in 2009. During the year ended December 31, 2008, we expensed $7.6 million related to the general bonus for 2008, of which $2.2 million will ultimately be settled in restricted shares (see Note 14). In as much as the performance goals were not met in 2008, no extraordinary performance bonus shall be paid for 2008.

14. Share-Based Compensation

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

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

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

At December 31, 2008, there were 1,767,826 shares of common stock available for award under our share-based payment plans. A summary of share activity pursuant to our share-based payment plans for the years ended December 31, 2008, 2007 and 2006 is as follows:

	2008		2007		2006	
	Restricted Shares	Weighted Average Grant Date Price Per Share	Restricted Shares	Weighted Average Grant Date Price Per Share	Restricted Shares	Weighted Average Grant Date Price Per Share
Nonvested, beginning of period	277,584	$29.17	102,860	$37.35	9,251	$32.43
Granted	204,139	32.41	348,675	27.39	165,732	37.30
Vested	(221,822)	30.80	(161,004)	30.42	(51,598)	37.22
Forfeited	(26,198)	30.30	(12,947)	30.51	(20,525)	35.03
Nonvested, end of period	233,703	30.33	277,584	29.17	102,860	37.35

During the year ended December 31, 2008, a total of 196,112 restricted shares of our common stock were granted to employees pursuant to our share-based payment plans, of which 61,497 shares vested in 2008, and the remainder, less any forfeited shares, will vest in equal increments in December 2009 and 2010. Also in 2008, our non-employee directors were granted a total of 8,027 restricted shares of our common stock, of which 488 shares vested in 2008. With certain exceptions, shares granted to our non-employee directors vest in three equal installments on the first, second and third anniversaries from the date of grant. Additionally in 2008, 10,941 restricted shares held by two former employees were vested upon termination of their employment.

During the year ended December 31, 2007, a total of 344,286 restricted shares of our common stock were granted to employees pursuant to our share-based payment plans. In 2008 and 2007, 100,892 and 111,822 of those shares vested, respectively, and the remainder, less any forfeited shares, will vest in December 2009. Also in 2007, our non-employee directors were granted a total of 4,389 restricted shares of our common stock. In 2008, 2,439 of those shares vested, and the remainder, less any forfeited shares, will vest in 2009 and 2010.

During the year ended December 31, 2006, a total of 161,784 restricted shares of our common stock were granted to employees pursuant to our share-based payment plans. In 2008, 2007 and 2006, 44,249, 47,866 and 51,598 of those shares vested, respectively. Also in 2006, our non-employee directors were granted a total of 3,948 restricted shares of our common stock. In each of 2008 and 2007, 1,316 of those shares vested and the remainder, less any forfeited shares, will vest in 2009.

The weighted average grant date fair value of shares granted under our share-based payment arrangements during the years ended December 31, 2008, 2007 and 2006 was $6.6 million, $9.5 million and $6.2 million, respectively. The weighted-average fair value of the shares that vested in 2008, 2007 and 2006 was $3.4 million, $4.8 million and $1.6 million, respectively, based on the closing prices on the dates of vesting. Total compensation expense under share-based payment arrangements was $8.1 million, $4.8 million and $4.1 million during the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, there was $5.7 million of total unrecognized share-based compensation expense related to restricted shares issued. Such amount is expected to be recognized in the period beginning January 2009 and ending April 2011.

15. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the Internal Revenue Code (the "401(k) Plan"), which covers those employees who meet the 401(k) Plan's eligibility requirements. During 2008, 2007 and 2006, the Company's matching contribution was 100% of each participant's contribution up to a maximum of 5% of the participant's compensation, subject to limitations imposed by the Internal Revenue Service. Our expenses relating to the 401(k) Plan were approximately $1.4 million, $1.2 million and $1.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

16. Earnings (Loss) Per Share

Basic earnings (loss) per share was calculated by dividing net income (loss) applicable to common shares by the weighted average number of common shares outstanding during the periods presented. For the year ended December 31, 2008, 174 thousand nonvested restricted shares outstanding were excluded from the computation of diluted loss per share because they were anti-dilutive. For the years ended December 31, 2007 and 2006, diluted earnings per share incorporates the potential dilutive impact of nonvested restricted shares outstanding during those periods.

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

	Year Ended December 31,		
	2008	2007	2006
Net income (loss) applicable to common shares	$(558,819)	$144,300	$199,104
Weighted average number of common shares (basic)	75,917	75,787	70,177
Weighted average nonvested common shares	—	152	40
Weighted average number of common shares (diluted)	75,917	75,939	70,217
Earnings (loss) per share:			
Basic	$ (7.36)	$ 1.90	$ 2.84
Diluted	(7.36)	1.90	2.84

17. Comprehensive Income (Loss)

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

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$(558,819)	$144,300	$199,104
Amounts reclassified to income, net of income tax of $263 in 2008, $84 in 2007 and $36 in 2006 (1)	488	(156)	67
Change in the fair value of interest rate swaps, net of income tax of $216 in 2007 and $345 in 2006	—	(402)	(640)
Comprehensive income (loss)	$(558,331)	$143,742	$198,531

(1) Includes interest rate swap settlements reclassified to income and amortization of amounts recorded in other comprehensive income upon the de-designation of our interest rate swap as a cash flow hedge. Refer to Note 8.

The balances in accumulated other comprehensive loss at December 31, 2008, 2007 and 2006 were related entirely to our interest rate swaps.

18. Related Party Transactions

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

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

The Company utilizes Brooke Companies, Inc. ("Brooke") on a non-exclusive basis to provide personnel to fill temporary and permanent staffing needs of the Company. Mr. Krohn's former wife owns 100% of Brooke. During the years ended December 31, 2008, 2007 and 2006, the Company paid Brooke approximately $0.3 million, $0.2 million and $0.5 million, respectively.

During 2008, 2007 and 2006, we paid approximately $0.3 million, $0.5 million and $0.4 million, respectively, to Adams and Reese LLP for legal services. A member of our board of directors, Ms. Boulet, serves as special counsel to Adams and Reese LLP.

As part of our relocation program for employees moving from Louisiana to Texas, the Company agreed to purchase their homes in Louisiana that had been actively marketed and had been for sale for a period greater than 90 days. The purchase price of an employee's home was based on a reasonable appraised value. During the year ended December 31, 2006, the Company purchased homes from three of our vice presidents pursuant to the relocation program for a total of approximately $3.8 million. Two of the homes were sold in 2006 for a total of approximately $2.3 million, resulting in a pre-tax loss of $0.4 million, which is included in general and administrative expenses for the year ended December 31, 2006. One of the homes was sold in 2007 for a total of approximately $0.9 million, resulting in a pre-tax loss of $0.2 million, which is in included in general and administrative expenses for the year ended December 31, 2007.

19. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2008	2007	2006
Cash paid for interest, net of interest capitalized of $19,292 in 2008 $25,100 in 2007 and $13,238 in 2006	$31,231	$31,573	$ 6,362
Cash paid for income taxes, net of refunds	26,591	34,030	47,993

In 2005, certain tax deadlines were postponed for taxpayers affected by Hurricane Katrina and, consequently, our estimated federal income tax payments due in the third and fourth quarters of 2005 were paid in October 2006 and totaled $33.5 million.

20. Selected Quarterly Financial Data – UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2008 and 2007 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2008				
Revenues	$356,495	$461,015	$289,793	$ 108,306
Operating income (loss) (1)	127,485	210,097	121,828	(1,266,555)
Net income (loss) (1)	79,806	134,610	78,181	(851,416)
Earnings (loss) per common share: (1)(2)				
Basic	1.05	1.77	1.03	(11.21)
Diluted	1.05	1.77	1.03	(11.21)
Year Ended December 31, 2007				
Revenues	$246,539	$272,563	$255,191	$ 339,456
Operating income	30,563	80,363	61,907	76,416
Net income	13,029	45,521	36,340	49,410
Earnings per common share: (2)				
Basic	0.17	0.60	0.48	0.65
Diluted	0.17	0.60	0.48	0.65

(1) In December 2008, the carrying amount of our oil and natural gas properties was written down by $1.2 billion ($768.8 million after-tax) through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008.

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

21. Supplemental Oil and Gas Disclosures—UNAUDITED

Capitalized Costs

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

	December 31, 2008	2007	2006
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 4,580.1	$ 3,297.0	$ 2,822.3
Unproved oil and natural gas properties and equipment	104.6	508.2	474.9
Accumulated depreciation, depletion and amortization	(3,210.4)	(1,547.4)	(1,038.3)
	$ 1,474.3	$ 2,257.8	$ 2,258.9

Costs Not Subject To Amortization

Costs not subject to amortization relate to unproved properties which are excluded from amortizable capital costs until it is determined that proved reserves can be assigned to such properties or until such time as the Company has made an evaluation that impairment has occurred. Subject to industry conditions, evaluation of most of these properties is expected to be completed within one to five years. The following table provides a summary of costs that are not being amortized as of December 31, 2008, by the year in which the costs were incurred (in millions):

	Total	2008	2007	2006	Prior to 2006
Costs excluded by year incurred:					
Acquisition costs	$80.6	$—	$—	$80.6	$—
Capitalized interest	18.5	8.0	7.6	2.9	—
	$99.1	$ 8.0	$ 7.6	$83.5	$—

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

The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2008, 2007, and 2006 (in millions):

	Year Ended December 31,		
	2008	2007	2006
Costs incurred (1):			
Proved property acquisitions	$139.0	$ 3.6	$ 841.0
Development	373.4	328.3	330.9
Exploration (2)	352.5	170.2	259.9
Unproved property acquisitions (3)	21.1	21.0	392.7
	$886.0	$523.1	$1,824.5

(1) Includes $111.1 million, $161.9 million and $173.8 million of asset retirement obligations accrued during the years ended December 31, 2008, 2007 and 2006, respectively.
(2) Includes seismic costs of approximately $14.5 million, $40.4 million and $7.0 million incurred during the years ended December 31, 2008, 2007 and 2006, respectively.
(3) The amounts for 2008, 2007 and 2006 include capitalized interest associated with properties classified as unproved at December 31, 2008, 2007 and 2006, respectively.

Depreciation, depletion, amortization and accretion expense

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

	Year Ended December 31,		
	2008	2007	2006
Depreciation, depletion, amortization and accretion per Mcfe	$5.33	$4.21	$3.40

Oil and Gas Reserve Information

Our net proved oil and gas reserves at December 31, 2008, 2007 and 2006 have been estimated by our independent petroleum consultant in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates. Our reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information.

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available. Decreases in the prices of oil and natural gas could have an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. We are not the operator with respect to approximately 18% of our proved undeveloped reserves and approximately 27% of our proved developed non-producing reserves, so we may not be in a position to control the timing of all development activities.

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

	Oil (MBbls)	Natural Gas (MMcf)	Total Oil and Natural Gas (MMcfe) (1)
Proved reserves as of December 31, 2005	45,937	215,920	491,544
Revisions of previous estimates	(1,242)	(5,692)	(13,149)
Extensions and discoveries (2)	7,255	65,759	109,289
Purchase of minerals in place (3)	10,165	185,697	246,686
Production	(6,456)	(60,447)	(99,181)
Proved reserves as of December 31, 2006	55,659	401,237	735,189
Revisions of previous estimates (4)	579	(22,176)	(18,702)
Extensions and discoveries (5)	2,910	30,979	48,441
Purchase of minerals in place	224	76	1,419
Sales of reserves	(74)	(570)	(1,015)
Production	(8,301)	(76,727)	(126,533)
Proved reserves as of December 31, 2007	50,997	332,819	638,799
Revisions of previous estimates (4)	(12,199)	(84,349)	(157,546)
Extensions and discoveries (6)	3,700	25,035	47,236
Purchase of minerals in place (3)	8,348	10,439	60,528
Production	(6,970)	(56,072)	(97,892)
Proved reserves as of December 31, 2008	43,876	227,872	491,125
Year-end proved developed reserves:			
2008	24,640	186,302	334,143
2007	26,666	235,293	395,291
2006	31,325	290,913	478,863

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

(2) Substantially all of these volumes are attributable to extensions and discoveries resulting from our participation in the drilling of 19 successful exploratory wells in 2006. Approximately 34% of the oil and natural gas equivalent volumes of such extensions and discoveries were attributable to nine new exploratory wells on the conventional shelf, 14% of such volumes were attributable to seven new exploratory wells on the deep shelf and 52% of such volumes were attributable to three exploratory deepwater wells.

(3) The amount for 2008 relates to volumes attributable to the purchase of the remaining working interest in Ship Shoal 349 field from Apache. The amount for 2006 primarily relates to volumes attributable to properties acquired by merger in the Kerr-McGee transaction. For additional details about these transactions, refer to Note 4.

(4) Revisions of previous estimates typically result from changes in commodity prices and changes in the performance of our properties. Damage to our facilities from tropical storms and hurricanes can also cause negative revisions. For 2008, negative revisions due to pricing, performance and hurricane damage were 105.0 Bcfe, 42.4 Bcfe and 10.1 Bcfe, respectively. For 2007, positive revisions due to price changes were 19.8 Bcfe and negative revisions due to performance were 38.5 Bcfe. Revisions due to price changes and performance were insignificant in 2006.

(5) Approximately 68% of these volumes are attributable to extensions and discoveries resulting from five of our six successful exploratory wells in 2007 and the deepening of the previously drilled No. 3 well at Green Canyon 82 "Healey." Approximately 37% of the oil and natural gas equivalent volumes of such extensions and discoveries were attributable to four new exploratory wells on the conventional shelf, 4% of such volumes were attributable to one new exploratory well on the deep shelf and 27% of such volumes were attributable to the deepening of the Green Canyon 82 No. 3 well.

(6) Substantially all of these volumes are attributable to extensions and discoveries resulting from our participation in the drilling of 18 successful exploratory wells in 2008, of which 16 were on the conventional shelf and two were on the deep shelf.

Standardized Measure of Discounted Future Net Cash Flows

The following presents the standardized measure of discounted future net cash flows related to our proved oil and gas reserves together with changes therein, as defined by the FASB. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on period-end prices. The period-end prices adjusted by lease for quality, transportation fees, energy content and regional price differentials related to proved reserves of natural gas approximated $6.17, $6.88 and $5.40 per Mcf and for oil and natural gas liquids were $37.71, $87.22 and $52.79 per barrel at December 31, 2008, 2007 and 2006, respectively. Future production and development costs are based on current costs with no escalations. Estimated future net cash flows, net of future income taxes, have been discounted to their present values based on a 10% annual discount rate.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and natural 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 2009 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$3,059,353	$ 6,737,806	$5,106,245
Future costs:			
Production	(667,132)	(920,193)	(693,633)
Development	(396,103)	(875,323)	(719,634)
Dismantlement and abandonment	(751,324)	(701,991)	(466,244)
Income taxes	(136,471)	(1,212,887)	(790,207)
Future net cash inflows before 10% discount	1,108,323	3,027,412	2,436,527
10% annual discount factor	(346,641)	(915,137)	(744,654)
	$ 761,682	$ 2,112,275	$1,691,873

	Year Ended December 31,		
	2008	2007	2006
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 2,112,275	$1,691,873	$1,596,446
Sales and transfers of oil and gas produced, net of production costs	(960,918)	(857,422)	(672,999)
Net changes in price, net of future production costs	(1,572,781)	1,371,346	(652,557)
Extensions and discoveries, net of future production and development costs	259,952	304,519	286,028
Changes in estimated future development costs	156,720	(401,536)	(65,614)
Previously estimated development costs incurred	275,344	207,111	146,046
Revisions of quantity estimates	(486,811)	(118,774)	(59,144)
Accretion of discount	272,483	205,484	217,772
Net change in income taxes	752,463	(297,548)	216,008
Purchases of reserves in-place	135,761	12,602	720,365
Sales of reserves in-place	—	(6,195)	—
Changes in production rates due to timing and other	(182,806)	815	(40,478)
Net increase (decrease) in standardized measure	(1,350,593)	420,402	95,427
Standardized measure, end of year	$ 761,682	$2,112,275	$1,691,873

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

None.

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

Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Exchange Act Rule 13a-15(b), 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 defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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, 2008 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, and that our controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008, is set forth in "*Management's Report on Internal Control over Financial Reporting*" included in Item 8. of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2008, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth in Item 4. of this report.

Item 11. *Executive Compensation*

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

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

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

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

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

Item 14. *Principal Accountant Fees and Services*

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

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Documents filed as a part of this report:

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

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

2. Exhibits:

Exhibit Number	Description
2.1	Agreement and Plan of Merger among Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil & Gas (Shelf) LLC, W&T Offshore, Inc., and W&T Energy V, LLC, effective October 1, 2005. (Incorporated by reference to Exhibit 99.1 of the Company's Current Report on Form 8-K, filed January 27, 2006)
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, filed 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, filed May 3, 2004 (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, filed May 3, 2004 (File No. 333-115103))

4.2	Indenture, dated as of June 13, 2007, between W&T Offshore, Inc., Wells Fargo Bank, National Association, as trustee, and the Guarantors, as defined therein. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed June 15, 2007)
10.1	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors. (Incorporated by reference to Exhibit 10.8 of the Company's Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103))
10.2*	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, filed May 3, 2004 (File No. 333-115103))
10.3*	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, filed October 26, 2005)
10.4	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, filed March 25, 2005)
10.5	Indemnification and Hold Harmless Agreement dated January 20, 2006, by and between S. James Nelson, Jr. and the Company. (Incorporated by reference to Exhibit 10.10 of the Company's Annual Report on Form 10-K, filed March 31, 2006)
10.6*	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, filed May 3, 2004 (File No. 333-115103))
10.7*	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/A, filed January 12, 2005 (File No. 333-115103))
10.8*	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, filed May 3, 2004 (File No. 333-115103))
10.9*	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, filed October 27, 2005)
10.10	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, filed May 3, 2004 (File No. 333-115103))
10.11	Third Amended and Restated Credit Agreement, dated May 26, 2006 by and between W&T Offshore, Inc. and Toronto Dominion (Texas) LLC, Lehman Commercial Paper Inc., Harris Nesbitt Financing, Inc., Fortis Capital Corp., Bank of Scotland, Natexis Banques Populaires and various financial institutions parties thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 7, 2006)
10.12	First Amendment to Third Amended and Restated Credit Agreement, dated June 9, 2006. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 7, 2006)
10.13	Second Amendment to Third Amended and Restated Credit Agreement, dated July 27, 2006. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 7, 2006)

10.14*	Employment Agreement dated July 11, 2006, by and between the W&T Offshore, Inc. and Stephen L. Schroeder. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 12, 2006)
10.15	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and Stephen L. Schroeder, dated July 5, 2006. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed July 12, 2006)
10.16*	First Amendment to Employment Agreement by and between W&T Offshore, Inc. and Reid Lea effective September 28, 2005. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed July 12, 2006)
10.17*	Employment Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed February 26, 2007)
10.18	Indemnification and Hold Harmless Agreement by and between W&T Offshore, Inc. and John D. Gibbons, dated as of February 26, 2007. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed February 26, 2007)
10.19	Purchase Agreement, dated June 8, 2007, by and among W&T Offshore, Inc., Morgan Stanley & Co. Incorporated (as Representative of the Initial Purchasers) and the Guarantors listed on Schedule IV attached thereto. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed June 15, 2007)
10.20	Third Amendment to Third Amended and Restated Credit Agreement, as amended, dated June 7, 2007. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 19, 2007)
10.21	Waiver and Fourth Amendment to Third Amended and Restated Credit Agreement, as amended, dated November 6, 2007. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed November 7, 2007)
10.22	Indemnification and Hold Harmless Agreement dated May 5, 2008, by and between Samir G. Gibara and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed May 14, 2008)
10.23	Fifth Amendment to Third Amended and Restated Credit Agreement, as amended, dated July 24, 2008. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 29, 2008)
10.24*	Employment Agreement, dated effective September 28, 2005, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed September 26, 2008)
10.25*	First Amendment to Employment Agreement, dated July 18, 2006, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed September 26, 2008)
10.26*	Second Amendment to Employment Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed September 26, 2008)
10.27	Indemnification and Hold Harmless Agreement, dated September 24, 2008, by and between W&T Offshore, Inc. and Jamie L. Vazquez. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed September 26, 2008)

10.28*	First Amendment to Employment Agreement, dated October 14, 2008, by and between W&T Offshore, Inc. and Tracy W. Krohn. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed October 20, 2008)
10.29*	Sixth Amendment to Third Amended and Restated Credit Agreement, as amended, dated December 18, 2008. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed December 23, 2008)
14.1	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, filed November 17, 2005)
21.1**	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.

* Management Contract or Compensatory Plan or Arrangement.

** Filed or furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

Bcf. Billion cubic feet.

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

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

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

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

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

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

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

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

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

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

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

Mcf. One thousand cubic feet.

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

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

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

Oil. Crude oil, condensate and natural gas liquids.

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

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

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

Proved reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and cost as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

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

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

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 2, 2009.

W&T OFFSHORE, INC.

By: /s/ JOHN D. GIBBONS

John D. Gibbons
Senior Vice President, 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 2, 2009.

/s/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ JOHN D. GIBBONS **John D. Gibbons**	Senior Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)
/s/ VIRGINIA BOULET **Virginia Boulet**	Director
/s/ J.F. FREEL **J.F. Freel**	Secretary and Director
/s/ SAMIR G. GIBARA **Samir G. Gibara**	Director
/s/ ROBERT I. ISRAEL **Robert I. Israel**	Director
/s/ S. JAMES NELSON, JR. **S. James Nelson, Jr.**	Director

Corporate Information

Company Profile

Founded in 1983, W&T Offshore is an independent oil and natural gas company focused primarily in the Gulf of Mexico area, including the deep-water and deep-shelf regions. We have grown through acquisition, exploitation and exploration, and now hold working interests in approximately 148 fields in federal and state waters and have interests in leases covering approximately 1.4 million gross acres. Our proved reserves at December 31, 2008, were 491.1 Bcfe, of which 68 percent were proved developed reserves and 46 percent were natural gas reserves.

Corporate Office

W&T Offshore, Inc.
Nine Greenway Plaza, Suite 300
Houston, TX 77046
Tel 713.626.8525
Web wtoffshore.com

Registrar & Transfer Agent

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

Computershare Investor Services, L.L.C.
2 North La Salle Street
Chicago, IL 60602
Tel 312.588.4990
Web us.computershare.com

Common Stock Information

The common stock of W&T Offshore, Inc. is traded on the New York Stock Exchange under the symbol WTI. As of March 23, 2009, there were 336 registered holders of our common stock.

Independent Auditors

Ernst & Young LLP, Houston, TX

Independent Petroleum Consultants

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

Annual Meeting

The Annual Meeting of Shareholders will be held at the Houston City Club, One City Club Drive, Houston, TX 77046 on May 4, 2009, at 10:00 a.m. Central Daylight Time.

Form 10-K & Quarterly Reports/Investor Contact

A copy of the W&T Offshore, Inc. Form 10-K for fiscal 2008, filed with the Securities and Exchange Commission, is available from the Company. Requests for investor-related information should be directed to Manuel Mondragon, Vice President of Finance, at the company's corporate office or on the Internet at www.wtoffshore.com. E-mail: investorrelations@wtoffshore.com. The W&T Offshore, Inc. Form 10-K is also available on our Web site at www.wtoffshore.com. The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to the Form 10-K. Tracy W. Krohn, our Chief Executive Officer, has also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

W&T OFFSHORE
INCORPORATED

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