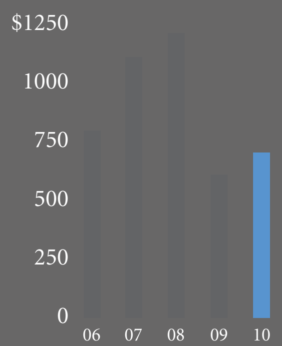
W&T OFFSHORE 2010 ANNUAL REPORT

FINANCIAL HIGHLIGHTS ($ in thousands, except as noted)

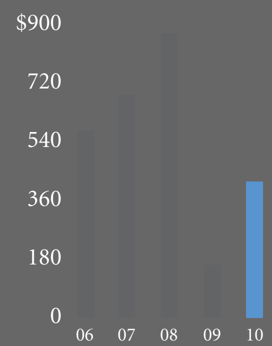
Year Ending December 31	**2010**	**2009**	**2008**	**2007**	**2006**
Income Statement					
Total Revenues	**$ 705,783**	$ 610,996	$ 1,215,609	$ 1,113,749	$ 800,466
Operating Income (Loss)	**$ 166,789**	$ (219,859)	$ (807,145)	$ 249,249	$ 317,615
Net Income (Loss)	**$ 117,892**	$ (187,919)	$ (558,819)	$ 144,300	$ 199,104
Cash-Flow Statement					
Operating Activities	**$ 464,772**	$ 156,266	$ 882,496	$ 688,597	$ 571,589
Capex (oil and natural gas properties)	**$ 415,653**	$ 276,134	$ 774,879	$ 361,235	$ 1,650,747
Balance Sheet					
Total Assets	**$ 1,424,094**	$ 1,326,833	$ 2,056,186	$ 2,812,204	$ 2,609,685
Long-Term Debt	**$ 450,000**	$ 450,000	$ 653,172	$ 654,764	$ 684,997
Shareholders' Equity	**$ 421,743**	$ 358,950	$ 572,227	$ 1,151,340	$ 1,042,917
Operating Data					
Natural Gas (Bcf)	**44.7**	51.6	56.1	76.7	60.4
Oil and NGLs (MMbls)	**7.1**	7.2	7.0	8.3	6.5
Total Natural Gas Equivalent (Bcfe)	**87.0**	94.8	97.9	126.5	99.2
Average Daily Equivalent Sales (MMcfe/d)	**238.4**	259.7	267.5	346.7	271.7
Average Realized Sales Price:					
Natural Gas ($/Mcf)	**$ 4.55**	$ 3.97	$ 9.40	$ 7.20	$ 7.08
Oil and NGLs ($/Bbl)	**$ 71.65**	$ 55.67	$ 98.72	$ 67.58	$ 57.70
Estimated Net Proved Reserves					
Natural Gas (Bcf)	**256.3**	165.8	227.9	332.8	401.2
Oil and NGLs (MMBbls)	**38.2**	34.2	43.9	51.0	55.7
Total Natural Gas Equivalent (Bcfe)	**485.4**	371.0	491.1	638.8	735.2
Total Proved Developed (Bcfe)	**391.3**	283.5	334.1	395.3	478.9
Proved Undeveloped (Bcfe)	**94.1**	87.5	157.0	243.5	256.3
Proved Developed Reserves as a % of Proved Reserves	**80.6%**	76.4%	68.0%	61.9%	65.1%

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 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 "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of the Form 10-K 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.

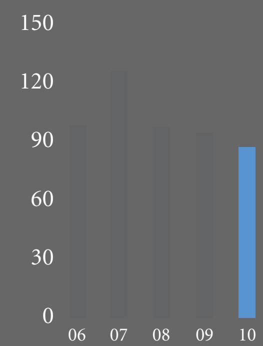
Revenues
(in millions)



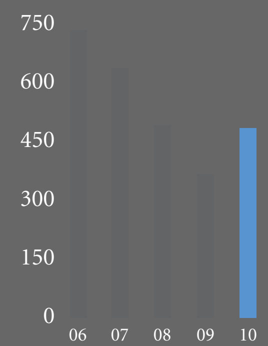
Cash Provided by Operating Activities
(in millions)



Production
(Bcfe)



Proved Reserves
(Bcfe)

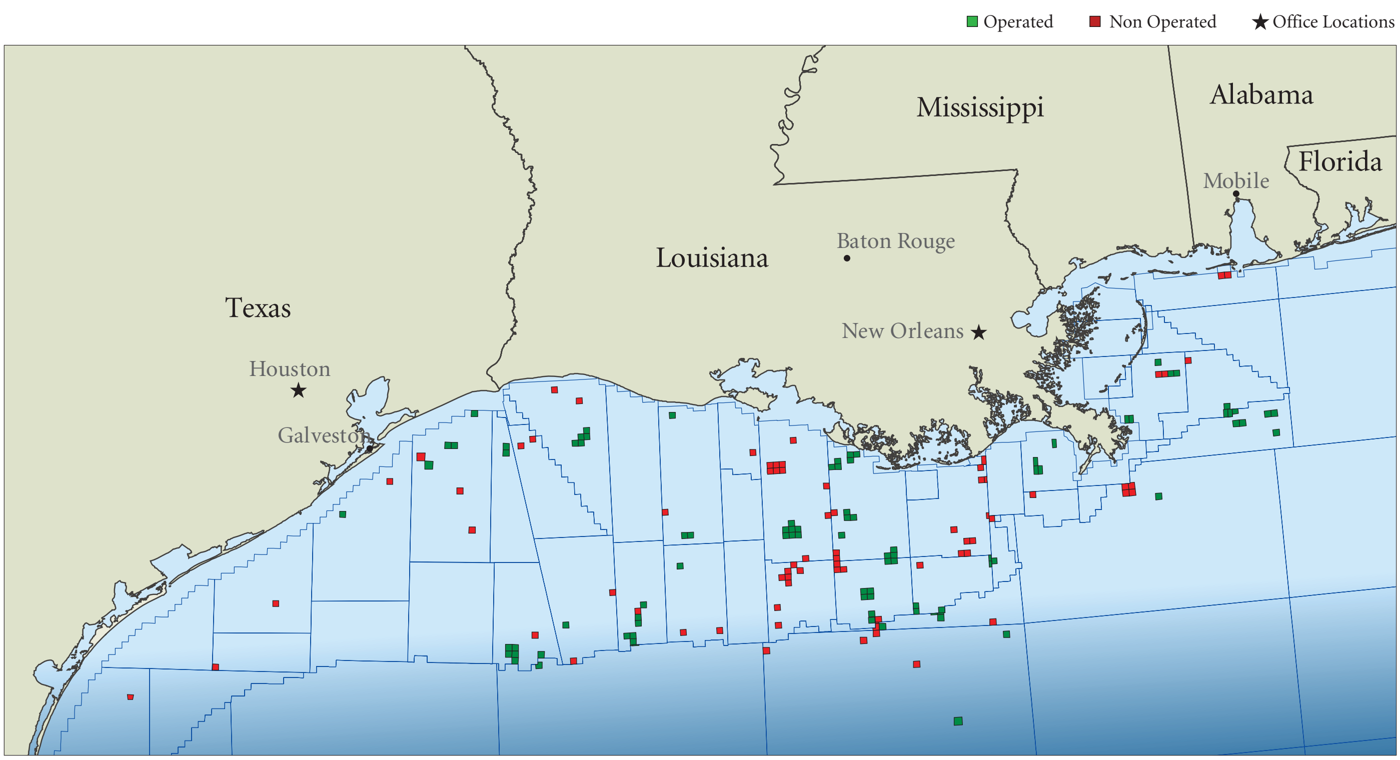


To Our Shareholders

We had an excellent and pivotal year in 2010 and we expect 2011 to be even better and more pivotal. Some highlights and developments of the Company in 2010:

- Net income and earnings per share in 2010 were $117.9 million and $1.58 per share, respectively, up $305.8 million and $4.09 per share, respectively, from the net loss we experienced in the prior year.
- Cash flow from operations nearly tripled.
- Total proved reserve replacement for the year was 231%. About three-quarters of the reserve growth came through acquisitions, while the remainder came through the drill bit, price and performance revisions and other changes. Year-end proved reserves rose 31 percent to 485.4 Bcfe despite the moratorium and continuing permitting issues in the Gulf of Mexico.
- Production was nearly flat with the prior year, as a result of permitting delays regarding major pipeline outages on third party pipeline repairs having to do with Macondo, divestitures of non-core assets completed in 2009 and natural reservoir declines. These declines were also offset by volumes from deep water properties we acquired from Shell and Total, which will contribute to production growth in 2011, and an active workover and re-completion program.
- We were able to fund our entire 2010 capital program, including acquisitions and normal and special dividends, with cash on hand, avoiding the need to incur debt or dilute equity.
- The market acknowledged our performance with almost a 50 percent increase in our stock price and we further rewarded shareholders in December with a special dividend of 66 cents per share.
- We continued to improve employee development programs and internal communications in order to enhance job skills and ensure that everyone moves in the same direction toward accomplishing Company goals.

All of these developments are already having a positive effect in 2011.



Offshore

"Deepwater still has a bright future for the production of oil and gas and we want to be part of that future."

The most significant events of 2010 were our deepwater acquisitions, along with successes through the drill bit. We originally intended to focus on expanding our onshore portfolio through a major acquisition, but subsequently realized that prices were too high to generate reasonable rates of return. Instead, we took advantage of deepwater opportunities. Deepwater had fallen out of favor as a result of the Macondo Deepwater Horizon incident, so prices were much more attractive. We added these reserves in the deepwater at better replacement costs than we'd seen in awhile--$1.63 per Mcfe before asset retirement obligations (ARO) and $1.79 per Mcfe net of ARO. These newly acquired properties will help drive production growth in 2011 and also provide additional upside opportunities.

We believed at the time and still believe that the fears over a prolonged deepwater moratorium will subside over time. Deepwater still has a bright future for the production of oil and gas and we want to be part of that future. Having said that, we are pursuing opportunities in the deepwater and shelf of the Gulf of Mexico. In addition, we will continue to pursue onshore opportunities that are suitable to grow the W&T portfolio. Our recent activity onshore has been in Texas and Louisiana, but we are open to other areas as well provided the economics are attractive.

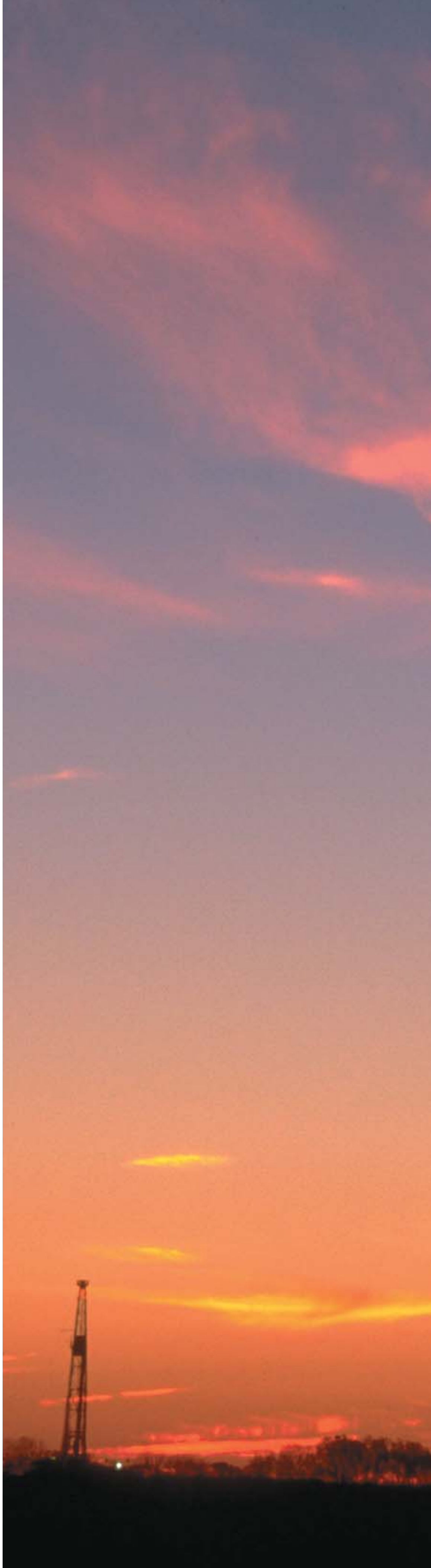
On the drilling front, in 2010 we pursued a relatively small drilling program to allow more room in the capital budget for acquisitions and by year-end were successful in five of the eight wells that were drilled. The five successes were all offshore—four exploratory and one development well. Our most successful well in terms of total proved reserves discovered in 2010 was the offshore Main Pass 108 E-3 well, in which we own a 100% working interest. That well alone added 10.5 Bcfe to our proved reserves and will be on line in March 2011. Although both onshore wells drilled in 2010 were unsuccessful, we are attracted to the high quality exploration prospects which are at a much lower cost than offshore wells; in other words we can participate in more high risk, high potential exploration wells increasing our overall chance of success. We plan to pursue both onshore and offshore exploration prospects in 2011. In fact, our budget for 2011 contemplates six wells onshore.

We enter 2011 a much stronger company, well positioned to take advantage of new opportunities. Our liquidity remains strong. Our strategy is working. We're efficient, patient and return-driven. Major goals for the year include:

- Meaningfully increase production over 2010 levels;
- Grow reserves;
- Drill the wells in our 2011 Capital Budget;
- Expand our onshore presence;
- Divest non-core properties;
- Continued focus on safety and environmental stewardship;
- Continue to enhance our staff;
- Better integration from a systems, processes and human resources standpoint;
- Improve our credit rating; and
- Improve our liquidity position.

Despite the lifting of the drilling moratorium in the Gulf of Mexico, permitting in the deep water and on the shelf is slow, but we believe this will improve, especially in light of concerns over oil supplies due to unrest in the Middle East and North Africa. The Gulf of Mexico is strategically vital; the United States obtains about 30 percent of our petroleum supply from that area.

Although our cash balance declined during the fourth quarter as we funded an acquisition, other capital expenditures and a special dividend, we still have nothing drawn under our revolver and availability remains at $405 million. Because the reserves acquired in the Shell transaction were virtually all proved developed producing (PDP), our borrowing base can be expanded. However, we will wait until the Spring redetermination to effect any changes in the borrowing base or the revolver size. Although our credit facility doesn't mature until July



Onshore

Due to the fact that many companies need to fund their shale projects, we perceive that opportunities exist to obtain conventional onshore assets through acquisitions and joint ventures.

Growth

"We enter 2011 a much stronger company, well positioned to take advantage of new opportunities."

2012, we intend to negotiate an extension of the current credit facility over the next few months. All in all, our liquidity continues to be strong, which will allow us to continue to grow.

Our capital budget for 2011 is $310 million, excluding acquisitions. Included in the budget are 14 drill wells—10 exploratory and four development wells. The 14 wells comprise five on the conventional shelf, one in the deepwater, two on the deep shelf and six onshore. Obviously, the timing of the deepwater well is solely dependent on the permitting process. One of the wells, which is offshore, is the Main Pass 180 A-2 well, and it has already been drilled and found 91 feet of high quality gas sands in three separate zones. This well is expected to be on line in April 2011. Another well, which is onshore, has also been drilled and found 22 feet of gas condensate and is on line. Another onshore well is currently drilling ahead. Other activity contemplated this year includes well completions, facilities work such as our compressor projects at Tahoe and MP 108, numerous workovers and recompletions, acquiring additional leaseholds and obtaining more seismic data on our properties. At this budget level, there is still plenty of liquidity to complete sizable acquisitions or joint ventures this year.

All of us at W&T are proud of our efforts in 2010 and excited about our future. We appreciate the continued support of our shareholders as we pursue our strategy to grow the Company profitably.

Tracy W. Krohn

Tracy W. Krohn
Founder, Chairman and CEO

Board of Directors

Samir G. Gibara, 71. Board member since May 2008. Mr. Gibara is a private investor. He served as Chairman of the Board and Chief Executive Officer of The Goodyear Tire & Rubber Company ("Goodyear") from 1996 to his retirement in 2002. Mr. Gibara brings extensive business and management expertise to the Company from his background as chief executive officer of Goodyear. Mr. Gibara is a graduate of Cairo University and holds a M.B.A. from Harvard University. Mr. Gibara also attended the Kellogg Graduate School of Management at Northwestern University.

Virginia Boulet, 57. Board member since March 2005. Ms. Boulet has over twenty years of experience in mergers and acquisitions, equity securities offerings, general business matters and counseling clients regarding compliance with federal securities laws and regulations. She received a B.A. in Medieval History from Yale University, and a J.D., cum laude, from Tulane University Law School. She is currently Chair of the Nominating and Corporate Governance Committee.

Robert I. Israel, 61. Board member since 2007. Mr. Israel, with over 30 years of corporate finance experience, has a strong business and financial background, especially in the natural resources sector. He is currently the Managing Partner of One Stone Energy Partners, a private equity fund, focused on investments in the oil and gas industry in the US and abroad. Mr. Israel holds a M.B.A. from Harvard University and a B.A. from Middlebury College

B. Frank Stanley, 56. Board member since 2009. Mr. Stanley has an extensive background in accounting and financial matters and is currently President and Chief Financial Officer of Retail Concepts, Inc., a privately-held retail chain of 25 stores in 13 states. Mr. Stanley holds a B.B.A. in Accounting from Texas A&M University and is a certified public accountant.

S. James Nelson, Jr., 68. Board member since January 2006. In 2004 Mr. Nelson retired after 15 years of service from Cal Dive International, Inc., a marine contractor and operator of offshore oil and natural gas properties and production facilities, where he was a founding shareholder, Chief Financial Officer from 1990 to 2000, Vice Chairman from 2000 to 2004 and a director. Mr. Nelson received a B.S. in Accounting from Holy Cross College and holds a M.B.A. from Harvard University. Mr. Nelson has an extensive background in public accounting both from his time as a Partner at Arthur Anderson & Co. and his time as Chief Financial Officer at Apache and other various companies. He is currently Chair of the Audit Committee and the Compensation Committee and also serves as Presiding Director.

J. F. Freel, 98. Served as a director since the Company's founding in 1983 and as Secretary of the Company since 1984. Mr. Freel has been actively involved in the oil and natural gas business since 1934, first as a geophysicist for eleven years with the Humble Oil and Refining Company, then, in 1945, as founder and President of Research Explorations, Inc., a geophysical survey contractor to major oil companies. In 1964, he became founder and President of Kiowa Minerals Company, a company that until 1983 engaged in development drilling operations in Texas and Louisiana.

Tracy W. Krohn, 56. Served as Chief Executive Officer since he founded the Company in 1983, as President from 1983 until 2008, as Chairman of the Board since 2004 and as Treasurer from 1997 until 2006. Mr. Krohn has been actively involved in the oil and gas business since graduating with a B.S. in Petroleum Engineering from Louisiana State University in 1978. He began his career as a petroleum engineer and offshore drilling supervisor with Mobil Oil Corporation. Prior to founding the Company, from 1982 to 1983, Mr. Krohn was senior engineer with Taylor Energy.

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, 2010

or

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

For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.

(Exact name of registrant as specified in its charter)

Texas	**72-1121985**
(State of incorporation)	**(IRS Employer Identification Number)**
Nine Greenway Plaza, Suite 300 Houston, Texas	**77046-0908**
(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 whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 $330,536,000 based on the closing sale price of $9.46 per share as reported by the New York Stock Exchange on June 30, 2010.

The number of shares of the registrant's common stock outstanding on March 4, 2011 was 74,464,258.

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.
TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities 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 ("SEC"). 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 primarily in the Gulf of Mexico. This is an area 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 0.9 million gross acres (0.6 million net acres) spanning across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and onshore. Approximately 82% of our total gross acreage is held-by-production.

During 2010, we also became active onshore and drilled one well in Louisiana and one well in Texas. We anticipate becoming more active onshore and our 2011 Capital Budget includes participating in six exploration wells in Texas. We anticipate that we will continue to expand our operations onshore.

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc. ("NSAI") our independent petroleum consultant, our total proved reserves at December 31, 2010 were 485.4 Bcfe. Approximately 81% of our reserves were classified as proved developed and 19% were classified as proved undeveloped. Classified by product, 53% of our reserves were natural gas and 47% were oil and natural gas liquids, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. We calculate that our total proved reserves had a present value of estimated future net revenues discounted at 10% ("PV-10") of $1,891.3 million. Our PV-10 after considering future cash outflows related to asset retirement obligations ("ARO") and without deducting future income taxes was $1,526.5 million and our standardized measure of discounted future cash flows was $1,179.1 million as of December 31, 2010. For additional information about our proved reserves and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, 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 will fit our profile and that we believe will add strategic and financial value to our company.

During the year 2010, we closed on two major acquisition transactions. On April 7, 2010, we entered into a Purchase and Sale Agreement ("PSA") with Total E&P USA ("Total") and on April 30, 2010, through our wholly-owned subsidiary, W&T Energy VI, LLC ("Energy VI"), we acquired all of Total's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $150 million, subject to customary closing adjustments, with an effective date of January 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $6.3 million. The properties acquired from Total are producing interests with future development potential, and include a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823). The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $115.0 million. This acquisition was funded with cash on hand.

On November 3, 2010, we entered into an Asset Purchase Agreement ("APA") with Shell Offshore Inc. ("Shell") and on November 4, 2010, through Energy VI, we acquired all of Shell's interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $138.0 million, subject to customary closing adjustments and preferential rights elections, with an effective date of September 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $18.0 million. The properties acquired from Shell are producing interests with future development potential, and include a 70% working interest in the Tahoe field (Viosca Knoll 783), 100% working interest in the Southeast Tahoe field (Viosca Knoll 784) and a 6.25% of 8/8ths overriding royalty interest in the Droshky field (Green Canyon 244). The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $121.9 million. Such amount is still subject to further adjustments upon final settlement. This acquisition was funded with cash on hand. See Item 8 *Financial Statements – Note 2 – Acquisitions and Divestitures* for additional information on acquisitions.

Also, on November 3, 2010, we entered into a letter of intent with Shell to acquire its 64.3% working interest in a shallow water producing property in the Gulf of Mexico along with certain associated assets. The letter of intent provides for a purchase price of $55.0 million, subject to customary closing adjustments, with an effective date of September 1, 2010. In addition, the ARO for plugging and abandonment with respect to this interest is estimated at $12.9 million. The transaction requires approval of a state regulatory agency and resolution of various other items. We expect to fund the acquisition with cash on hand and borrowings under our revolving loan facility.

Our exploration efforts historically have been in geographies in fairly close proximity to areas of known proved reserves, which we believe reduces our risks. 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 water depth, 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 and onshore. 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. When projects are extremely capital intensive and involve substantial risk, we often seek participants to share the risk. The number of productive wells drilled on a gross basis was 5, 10, and 20 for the years 2010, 2009 and 2008, respectively.

From time to time, we sell various properties that we determine are no longer part of our business strategy. We are currently marketing certain properties that we consider non-core.

We generally sell our oil and natural gas at the wellhead at current market prices or 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. Our products are marketed 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.

Our total capital expenditure budget for 2011 is $310 million which excludes acquisitions. The budget includes $161 million of capital to drill and evaluate 14 wells including 10 exploration and four development wells. The 14 wells are comprised of five on the conventional shelf, one in the deepwater, two on the deep shelf of the Gulf of Mexico and six wells located onshore. The budget also includes amounts for well completions, facilities capital, recompletions, seismic and leasehold items. Our acquisition plans thus far in 2011 include acquiring the additional properties from Shell pursuant to the letter of intent which is discussed above. There may be additional acquisitions pursued or completed in 2011 should attractive opportunities arise. We anticipate funding our 2011 capital budget and acquisitions with internally generated cash flow, cash on hand and borrowings under our revolving loan facility. Our 2011 capital budget and acquisition plans are subject to change as conditions warrant and our budget is sufficiently flexible such that most any change can be made without penalty. We strive to be as flexible as possible and believe this strategy holds the best promise for value creation and growth and managing the volatility inherent in our business.

Business Strategy

We plan to continue to acquire and exploit oil and natural gas reserves on the Outer Continental Shelf ("OCS"), the area of our historical success and technical expertise, which we believe will yield rates of return sufficient to remain competitive in our industry. 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 volatility, we also believe that other less well-capitalized producers may seek buyers for their properties both onshore and offshore, which could create opportunities for us.

We believe a portion of our Gulf of Mexico 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 is usually 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.

In addition to pursuing opportunities in the Gulf of Mexico, we also plan to pursue other areas that are compatible with our technical expertise and could yield rates of return sufficient to remain competitive in our industry. As described above, we have acquired interests in various onshore properties and anticipate acquiring or expanding our onshore holdings in the states of Alabama, Louisiana, Mississippi, and Texas through acquisitions or exploration and development activities.

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 drilling 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.

Competition

The oil and natural gas industry is highly competitive. We currently operate almost exclusively in the Gulf of Mexico area and compete for the acquisition of oil and natural gas properties primarily on the basis of price 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. 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 to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, in 2010 we sold over 10% of our production to each of Shell Trading (US) Co. and Conoco Phillips. See Item 8 *Financial Statements – Note 1 – Significant Accounting Policies – Concentration of Credit Risk* 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.

In addition, the Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, and financial condition.

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. The rates for such storage and transportation services are subject to FERC ratemaking authority, and FERC exercises its authority either by applying cost-of-service principles or granting market based rates.

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. We note that the RRC is subject to a sunset condition. If the Texas Legislature does not continue the RRC, the RRC will be abolished effective September 1, 2011, and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the RRC. We cannot tell what, if any, changes will be made to the RRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but we do not believe that any such changes would affect our business in a way that would be materially different from the way such changes would affect our competitors.

The Outer Continental Shelf Lands Act ("OCSLA"), which is administered by the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE" and formerly the Minerals Management Service) 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 BOEMRE 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 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.

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, the BOEMRE 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. The price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. Interstate transportation rates for oil, natural gas liquids, and other products are regulated by the FERC. The FERC has established an indexing system for such transportation, which allows such pipelines to take an annual inflation-based rate increase.

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.

In 2010, there were numerous new and proposed regulations related to oil and gas exploration and production activities. See Item 1A *Risk Factors* for more information.

Federal leases. Most of our operations are conducted on federal oil and natural gas leases, which are administered by the BOEMRE pursuant to the OCSLA. These leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEMRE regulations and orders that are subject to interpretation and change by the BOEMRE. The BOEMRE 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. See Item 1A, *Risk Factors*, for more information on new regulations.

To cover the various obligations of lessees on the OCS, the BOEMRE 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 BOEMRE. As many BOEMRE regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. Under some circumstances, the BOEMRE 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. See Item 1A, *Risk Factors – BP's Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable* for more information.

The BOEMRE 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 BOEMRE.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEMRE 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 BOEMRE 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. It is possible that similar, if not more stringent, requirements will be issued by the BOEMRE for future hurricane seasons. New requirements, if any, could increase our operating costs.

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.

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.

In December 2009, the U.S. Environmental Protection Agency (the "EPA") determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The primary federal law for oil spill liability is the Oil Pollution Act (the “OPA”) which amends and augments oil spill provisions of the Clean Water Act. OPA imposes certain duties and liabilities on “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters, including the OCS or adjoining shorelines. A liable “responsible party” includes the owner or operator of an onshore facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several, strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to $150 million in certain situations. As a result of the BP Deepwater Horizon incident, legislation has been proposed in Congress to increase the minimum level of financial responsibility to $300 million or more. If OPA is amended to increase the minimum level of financial responsibility to $300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by OPA, we may be forced to sell our properties or operations located on the OCS or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if there were to occur an oil discharge or substantial threat of discharge, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

The Safe Drinking Water Act (the “SDWA”) regulates, among other things, underground injection operations. Legislation has been proposed in Congress to make the injection of oil and gas well completion fluids subject to the SDWA. If enacted, this legislation would impose on hydraulic fracturing operations permit and financial assurance requirements, well construction specifications, monitoring, reporting and recordkeeping obligations, and more stringent plugging and abandonment requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the process could adversely affect ground water. If this or similar legislation is enacted and we engage in such activity, we could incur substantial compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

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 include regulations regarding the taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The BOEMRE also issues numerous regulations under the nomenclature Notice to Lessees ("NTL") that provide formal guidelines on implementation of OCS regulations and standards. We believe we are in compliance in all material respects with the requirements regarding protection of marine species.

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 regulations issued 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. These and other protected areas may require certain mitigation measures to avoid harm to wildlife, and such laws and regulations may 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.

Naturally Occurring Radioactive Materials ("NORM") may contaminate minerals, minerals extraction and processing equipment used in the oil and natural gas industry. The waste resulting 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 laws 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, 2010, we employed 305 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 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 on Form 10-K 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 450 Fifth Street, N.W., 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

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, terrorism or political instability in oil producing countries;
- 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. For example, the prices of oil and natural gas declined substantially during the second half of 2008 and impacted production volumes. Natural gas prices have been negatively affected by the domestic economy, high levels of stored natural gas and weather conditions affecting demand. There have been significant recent development activities in shale and other resource plays, which have the potential to yield a significant amount of natural gas production, and to a lesser extent oil production, in the United States. The potential increases in natural gas supplies resulting from the large-scale development of these unconventional resource reserves could continue to have an adverse impact on the price of natural gas. An environment of depressed oil and natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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. Additionally, we recorded a ceiling test impairment at March 31, 2009 of $218.9 million primarily as a result of a further decline in natural gas prices as of March 31, 2009. We did not have any impairment write-down in 2010. Declines in oil and natural gas prices after December 31, 2010 may require us to record additional ceiling test impairments in the future. 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 would 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 Item 8 *Financial Statements – Note 1 – Significant Accounting Policies* for a discussion of the ceiling test.

BP's Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf of Mexico, some of which may be unforeseeable.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in ultra deep water in the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, there have been many proposals by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. Beginning in May 2010, the BOEMRE issued a series of NTLs imposing a variety of new safety measures and permitting requirements and implemented a six-month moratorium on drilling activities in federal offshore waters.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued by the BOEMRE, there have been numerous additional proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and oil spill that could affect our operations and cause us to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations in the Gulf of Mexico by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, and, further, could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf of Mexico more difficult, more time consuming, and more costly. For example, a variety of amendments to the OPA have been proposed in response to the Deepwater Horizon incident. OPA and regulations adopted pursuant to OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the OCS, which includes the Gulf of Mexico where we have substantial offshore operations. OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to $150 million in certain situations. Legislation has been proposed in Congress to amend OPA to increase the minimum level of financial responsibility to $300 million or more. If OPA is amended to increase the minimum level of financial responsibility to $300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by OPA, we may be forced to sell our properties or operations located on the OCS or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased.

New regulatory requirements, NTLs and permitting procedures recently imposed by the BOEMRE could significantly delay our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the BP Deepwater Horizon incident in the U.S. Gulf of Mexico, the BOEMRE issued a series of NTLs imposing new requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.

- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

As a result of the issuance of these new NTLs and the lack of detail therein, BOEMRE has been taking much longer to review and approve permits for new wells. Due to the extremely slow pace of permit review and approval, various industry sources have determined that BOEMRE may take six months or longer to approve applications for drilling permits that were previously approved in less than 30 days. These NTLs also increase the cost of preparing each permit application and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS. The delay in granting permits could also have the effect of causing some of our leases to lapse as a result of failure to commence drilling or continue production operations.

New NTLs recently imposed by the BOEMRE could significantly impact the cost of operating our business.

In addition to the NTLs discussed previously, the BOEMRE issued NTL No. 2010-G05 dated effective October 15, 2010 that establishes a more stringent regimen for the timely decommissioning of what is known as "idle iron" – wells, platforms and pipelines that are no longer producing or serving exploration or support functions related to an operator's lease – in the Gulf of Mexico. This NTL sets forth more stringent standards for decommissioning timing requirements by applying the requirement that any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years. Plugging or abandonment of wells may be delayed by two years if all of the well's hydrocarbon and sulphur zones are appropriately isolated. Similarly, platforms or other facilities that are no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to historical decommissioning efforts may serve to increase, perhaps materially, our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future ARO required to meet such increased costs. For the year 2010, we increased our estimate of ARO by $18.7 million based on our expected acceleration in timing for such obligations as a result of implementing this NTL. (For additional details, refer to Item 8 *Financial Statements – Note 5 – Asset Retirement Obligations.*) However, the potential increase in decommissioning activity in the Gulf of Mexico over the next few years as a result of the NTL could likely result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

We were adversely affected by a recession in the United States and global economy.

The United States and other world economies are slowly recovering from a recession which began in 2008 and extended into 2009. The recession that began in 2008 caused a collapse in oil and natural gas prices causing us to write down the value of our reserves at the end of 2008 and early 2009. These write downs significantly reduced our stockholders equity, increased our financial leverage, reduced the market value of our common stock and reduced the market value of our long-term debt. While the recession officially ended in 2009, the growth in 2010 has only offset the declines in 2009. There are likely to be significant long-term effects resulting from the recession and the credit market crisis, including a future economic growth rate that is slower than what was experienced before the recession began. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. A lower future economic growth rate will result in decreased demand growth for our oil and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

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 $405.5 million. Availability is determined periodically at the discretion of our 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 natural 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 and our ability to replace reserves.

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. The insurance market may change dramatically in the future due to the major oil spill that occurred in 2010 as a result of a fire and explosion aboard BP's Deepwater Horizon. 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.

Included in lease operating expenses for the years ended December 31, 2009 and 2008 are hurricane remediation costs, net, of $18.4 million and $17.7 million, respectively, related to Hurricanes Ike and Gustav that were either not yet approved by our insurance underwriters' adjuster or were not covered by insurance. In 2010, hurricane remediation costs were a net credit of $11.7 million, as approved claims for costs incurred in prior years exceeded costs incurred during 2010.

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

Due to increased insurance claims in recent years associated with hurricanes in the Gulf of Mexico, property damage and well control insurance coverage has become more limited and the cost of such coverage has become more volatile. In June 2010, we renewed our insurance policies covering well control and hurricane damage at an annual cost of approximately $20.7 million. In 2009, our annual cost was approximately $35.2 million, which was a substantial increase from 2008 levels. The current policy limits for well control and named windstorm damage are $100 million and $85 million, respectively, with an additional $100 million for well control on six wells at our Ship Shoal 349 field and six wells at our Matterhorn field. A retention amount of $5 million for well control and $35 million per named windstorm occurrence must be satisfied by us before we are indemnified for losses, and certain properties we have deemed as non-core are not covered for hurricane damage. As of December 31, 2010, properties representing approximately 80% of our PV-10 value of proved reserves are covered under our current insurance policies for named windstorm damage. The properties purchased from Shell comprise approximately 11% of our PV-10 and are not currently covered for named windstorm damage. Since we closed on the Shell properties near the end of named windstorm season (June 1 to November 30) and our renewal is before the next named windstorm season, we elected not to purchase named windstorm insurance on the Shell assets for this interim period as we considered the probability of a named windstorm as remote. Our insurers may not continue to offer this type and level of coverage to us, our costs may increase substantially as a result of increased premiums and the losses that may have been previously insured may no longer be insured. The occurrence of any or all of these could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future 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.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risk in the marketing of our oil and natural gas, we may periodically enter into oil and natural gas price hedging arrangements with respect to a portion of our expected production. For example, during 2010, we entered into option contracts to mitigate commodity price risk relating to approximately 1.9 MMBbls and 1.1 MMBbls of our anticipated production in 2011 and 2012, respectively. We do not enter into derivative instruments for speculative trading purposes. While hedging transactions are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income if oil and natural gas prices were to rise substantially over the price established by the hedge. 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 counterparties to the hedge contracts fail to perform under the terms of the contracts.

We may be limited in our ability to maintain proved undeveloped reserves under current SEC guidance.

Current SEC guidance require proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped.

As of December 31, 2010, approximately 19% of our total proved reserves were undeveloped and approximately 32% 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 for exploiting and producing 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 10% 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, which could result in the write-off of previously recognized reserves.

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

Our proved reserves increased in 2010 due to acquisitions but had declined in each of the prior three years. 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.

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 at sufficient levels 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, 53% of our total proved reserves are depleted within three years. As a result, our need to replace reserves and production 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 in sufficient quantities to sustain our current production levels or to grow production beyond current levels. 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 with cash on hand, cash provided by operations, securities offerings and bank borrowings. 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. Any reductions in our capital expenditures to stay within internally generated cash flow (which could be 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 replace our proved 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 BOEMRE 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 because our operations are almost exclusively in the Gulf of Mexico.

We are required to record a liability for the present value of our ARO to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. 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 may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. For example, 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 rather than structurally intact. Accordingly, our estimate of future ARO could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

As described above in the risk factor titled "*New NTLs recently imposed by the BOEMRE could significantly impact the cost of operating our business*", the BOEMRE's NTL 2010-G05 increased our liability for ARO by accelerating the time frame for plugging, abandonment and removal for some of our platforms. In addition, the potential increase in decommissioning activity in the Gulf of Mexico over the next several years as a result of the NTL could likely result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

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 may 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 anticipated results 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, geological issues 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, discharges of toxic gases or encountering naturally occurring radioactive materials.

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;
- repairs required to resume operations; and
- loss of reserves.

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 U.S. 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;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- 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 2009 and 2008, net production of approximately 8.7 Bcfe and 21.7 Bcfe, respectively, was deferred as a result of damage caused primarily by Hurricane Ike.

As we increase our onshore operations, we will be subject to different risk factors that could impact loss of revenues or curtailment of production for these geographies.

Onshore oil and gas exploration and production operations share similar risk factors to offshore, but may have different regulations, interpretation of regulations and enforcement by the particular state in which the operations are conducted. As our experience has primarily been with offshore operations, our ability to comply with the various state regulations and work effectively with the state agencies may impact our operations.

Properties that we acquire 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, which may include 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 historically not physically inspected every well, platform or pipeline. Even if we had physically 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. 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.

Estimates of our proved reserves depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in the estimates or underlying assumptions will materially affect the quantities of and present value of future net revenues from 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, 2010. 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,* Item 2 *Properties* and Item 8 *Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures*.

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 oil and natural gas 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 the 12-month unweighted first-day-of-the-month average price for each product and costs in effect 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 accumulation 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, deep shelf and various onshore 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 positive rates 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, which in most cases are 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. In addition, third-party platforms could be damaged or destroyed by hurricanes which could reduce or eliminate our ability to market our production. As of December 31, 2010, five fields, accounting for approximately 2.9 Bcfe (or 3%) of our 2010 production, are tied back or are planned to be tied back to separate, third-party owned platforms. 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. For example, damage caused primarily by Hurricane Ike to third-party pipelines and other facilities resulted in deferred net production of approximately 8.7 Bcfe and 21.7 Bcfe for the years 2009 and 2008, respectively. Another example is a third-party pipeline used by our Main Pass 108 field has been shut in since June 2010, which we believe has caused approximately 4.9 Bcfe of production to be deferred during 2010.

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 natural 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 explanation 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;
- loss of our leases;
- 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 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.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please see – *Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.*

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

We operate a production platform in a highly regulated National Marine Sanctuary, which increases our compliance costs and subjects us to risk of significant fines and penalties if we do not maintain rigorous compliance.

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.

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; John D. Gibbons, our Senior Vice President, Chief Financial Officer and Chief Accounting Officer; Stephen L. Schroeder, our Senior Vice President and Chief Operating Officer, Jesus G. Melendrez, our Senior Vice President and Chief Commercial Officer, and Thomas F. Getten, our Vice President, General Counsel and Assistant Secretary, 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 Part I—*Executive Officers of the Registrant* included in this Annual Report on Form 10-K 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 natural 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 the U.S. Gulf of Mexico, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and production, and any such change could have a negative effect on the results of our operations.

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.

Risks Related to Financings

Adverse changes in the financial and credit markets could negatively impact our economic growth. In addition, 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.

During 2010, financial markets were robust and record amounts of debt and equity financing were completed by many in our industry. For 2011 to date, treasury yields have increased due to worries about federal policies and economic turmoil in Greece, Ireland, Spain and other countries. We did not access the capital markets in 2010 as we were able to fund capital expenditures and acquisitions with internally generated cash flow and cash on hand.

In 2009, the global financial markets and economic conditions were severely distressed. There were concerns of bank failures and liquidity concerns whether our banks would be able to meet their commitments under credit arrangements in place during that time. This caused limited financing transactions being completed. In addition, prices for oil and natural gas had decreased from 2008.

Subsequent to the credit market disruptions in 2009, we have not accessed the debt or equity markets for funding, nor have we renewed or replaced our revolving loan facility. In November 2010, we received notification from our lenders that our borrowing base was reaffirmed at the existing level. The Credit Agreement matures in July 2012 and our expectation is to amend the agreement or secure new credit arrangements prior to the maturity date. Various factors will be evaluated, including our credit rating, our reserves and our production profile, in determining the amount of credit and cost of obtaining credit. While we believe we will be able to obtain credit, there can be no assurance that we would be able to access the capital market on terms and conditions that would be acceptable to us, if the need were to arise.

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.

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 become 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 any future 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 52.7% of our voting interests as of February 25, 2011. 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. 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 or stockholders. As a result, the market price of our common stock could be adversely affected.

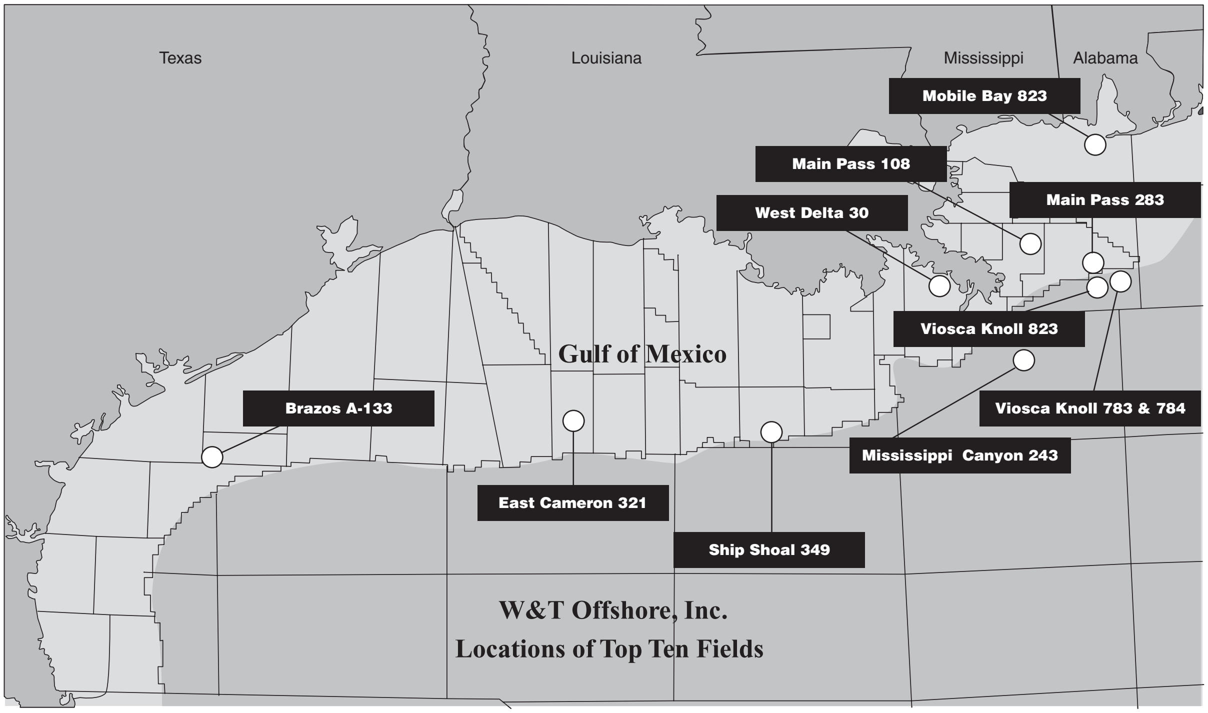
Due to Mr. Krohn's ownership and control, we are exempted from many New York Stock Exchange corporate governance rules, and as a result our other shareholders may not have the protections set forth in those rules, particularly in the event of conflicts of interest with Mr. Krohn.

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 ("NYSE"). As such, we are not required to comply with certain corporate governance rules of the NYSE 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. 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.

Item 2. *Properties*



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 as of December 31, 2010, based on quantities of proved reserves on a natural gas equivalent basis. At December 31, 2010, these fields accounted for approximately 77% of our proved reserves.

Field Name	Field Category	Operator	Percent Natural Gas of Net Reserves (1)	2010 Average Daily Equivalent Sales Rate (MMcfe/d) (1)	
				Gross	Net
Ship Shoal 349	Shelf	W&T	17%	17.0	13.8
Viosca Knoll 783/784 (Tahoe/SE Tahoe)	Deepwater	W&T	94%	45.6	30.7
Main Pass 108	Shelf	W&T	77%	9.5	6.3
Miss. Canyon 243 (Matterhorn)	Deepwater	W&T	19%	27.3	25.6
Viosca Knoll 823 (Virgo)	Deepwater	W&T	72%	10.4	5.8
Brazos A-133	Shelf	Apache	99%	32.2	6.5
Main Pass 283	Shelf	W&T	46%	27.2	19.4
West Delta 30	Shelf	W&T and EPL (2)	5%	2.3	1.9
Mobile Bay 823	Deep shelf	ExxonMobil	82%	55.3	5.1
East Cameron 321	Shelf	W&T	19%	15.1	12.1

(1) Determined by the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

(2) W&T operates all down hole operations on well bores in which we have 100% working interests.

On December 31, 2010 we had two fields of major significance (having proved reserves which comprise 15% or more of the Company's total proved reserves, calculated on a natural gas equivalent basis). The Ship Shoal 349 field is located on the conventional shelf and the Viosca Knoll 783/784 field (Tahoe/SE Tahoe) is located in the deepwater. Below is a description of these fields.

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 became the operator of the field in December 2004. In early 2008, we acquired the remaining working interest from Apache Corporation and we now own a 100% working interest in this field. Cumulative field production through 2010 is approximately 176 Bcfe gross. This field is a sub-salt development with five productive horizons below salt at depths ranging to 17,000 feet. As of December 31, 2010, 22 wells have been drilled, of which 13 have been successful. During 2010, we developed a reservoir simulation model to determine the most optimal future development plan. As a result, in 2011, we plan to drill two development wells. Total proved reserves associated with our interest in this field were 113.3 Bcfe at December 31, 2010.

The following presents historical information about our produced oil and natural gas volumes from Ship Shoal 349 field over the past three fiscal years.

	Year Ended December 31,		
	2010	**2009**	**2008**
Net sales:			
Natural gas (Bcf)	0.9	0.8	0.7
Oil and NGLs (MMBbls)	0.7	0.7	0.7
Total natural gas equivalent (Bcfe)	5.0	5.1	4.6
Average realized sales prices:			
Natural gas ($/Mcf)	$ 4.88	$ 4.56	$10.80
Oil and NGLs ($/Bbl)	71.58	54.02	94.83
Natural gas equivalent ($/Mcfe)	10.72	8.33	15.05
Average per Mcfe ($/Mcfe):			
Production costs (1)	$ 2.20	$ 2.43	$ 1.33

(1) Includes lease operating expenses and gathering and transportation costs. The increase in 2009 production costs per Mcfe compared to 2008 primarily relates to higher insurance costs in 2009. In addition to our standard insurance policies for well control and hurricane damage, we have an additional $100 million of insurance for well control and hurricane damage on our Ship Shoal 349 field.

Viosca Knoll 783 Field. (Viosca Knoll 783 Field (Tahoe) and Viosca Knoll 784 Field (SE Tahoe) The Viosca Knoll 783 field is located off the coast of Louisiana, approximately 140 miles southeast of New Orleans, in 1,500 to 1,700 feet of water. The field area covers Viosca Knoll blocks 783 and 784, with a subsea tieback to a platform in Main Pass 252. Shell discovered Tahoe field in 1984 and SE Tahoe field in 1996. We acquired a 70% working interest in Tahoe field and a 100% working interest in SE Tahoe field from Shell in 2010. Cumulative field production through 2010 is approximately 507 Bcfe gross. Tahoe field is a supra-salt (above the salt layer) development with two productive horizons at depths ranging to 10,300 feet. SE Tahoe field is also a supra-salt development with one productive horizon at a depth of 9,325 feet. As of December 31, 2010, 16 wells have been drilled at the Tahoe field, of which 6 have been successful and one successful well has been drilled at the SE Tahoe field. Total proved reserves associated with our interest in these fields were 72.4 Bcfe at December 31, 2010.

The following presents historical information about our produced oil and natural gas volumes from Viosca Knoll 783 from the acquisition date of November 4, 2011 through December 31, 2011. As we have had limited history with Viosca Knoll 783, the amounts below may not be representative of future results.

	November/ December 2010
Net sales:	
Natural gas (Bcf)	1.6
Oil and NGLs (MMBbls)	—
Total natural gas equivalent (Bcfe)	1.9
Average realized sales prices:	
Natural gas ($/Mcf)	$ 3.95
Oil and NGLs ($/Bbl)	62.88
Natural gas equivalent ($/Mcfe)	4.85
Average per Mcfe ($/Mcfe):	
Production costs (1)	$ 0.78

(1) Includes lease operating expenses and gathering and transportation costs.

The following is a description of the remainder of our top ten properties, measured by proved reserves at December 31, 2010, of which five are located on the conventional shelf, two are 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 proved reserves which comprise less than 15% of the Company's total proved reserves, calculated on a natural gas equivalent basis).

Main Pass 108 Field. Main Pass 108 field consists of Main Pass blocks 94, 107, 108 and 109. This field is located off the coast of Louisiana approximately 50 miles east of Venice in 50 feet of water. We acquired our working interests in these blocks, which range from 33% to 100%, in a transaction with Kerr-McGee Oil and Gas Corporation. 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, 2010, 52 wells have been drilled in this field, of which 38 were successful. Cumulative field production through 2010 is approximately 283 Bcfe gross. During 2010, additional wells were successfully drilled, recompleted or workovers were performed to increase production and add reserves. However, the third party pipeline that is used to transport production from the field has been shut in since June 2010. We currently expect production from the field to resume in the first half of 2011.

Mississippi Canyon 243 Field. (Matterhorn) Mississippi Canyon 243 field is located off the coast of Louisiana, approximately 100 miles southeast of New Orleans, in 2,552 feet of water. The field area covers Mississippi Canyon block 243, with a single production platform on Mississippi Canyon block 243. Société Nationale Elf Aquitaine discovered the field in 2002. We acquired a 100% working interest in the field from Total in 2010. Cumulative field production through 2010 is approximately 117 Bcfe gross. This field is a supra-salt development with 17 productive horizons at depths ranging to 9,850 feet. As of December 31, 2010, 17 wells have been drilled, of which 8 have been successful. During December 2010, production from this field, net to our interest, averaged 4.2 MMcf of natural gas per day and 3,393 Bbls of oil per day, or 24.6 MMcfe per day.

Viosca Knoll 823 Field. (Virgo) Viosca Knoll 823 field is located off the coast of Louisiana, approximately 125 miles southeast of New Orleans, in 1,014 feet of water. The field area covers Viosca Knoll block 823 and Viosca Knoll block 822, with a single production platform on Viosca Knoll block 823. Total discovered the field in 1997. We acquired a 64% working interest in the field from Total in 2010. Cumulative field production through 2010 is approximately 115 Bcfe gross. This field is a supra-salt development with 17 productive horizons at depths ranging to 13,335 feet. As of December 31, 2010, 12 wells have been drilled, of which 10 have been successful. During December 2010, production from this field, net to our interest, averaged 3.9 MMcf of natural gas per day and 170 Bbls of oil per day, or 4.9 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 the same year. There are five active platforms, three of which are production platforms. Cumulative field production through 2010 is approximately 849 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, of which 17 were successful. We own a 25% working interest that was obtained through a transaction with Kerr-McGee. During December 2010, production from this field, net to our interest, averaged 6.7 MMcf of natural gas per day and 18 Bbls of oil per day, or 6.8 MMcfe per day.

Main Pass 283 Field. Main Pass 283 field consists of Main Pass blocks 284, 279 and 283 and Viosca Knoll Block 734. This field is located off the coast of Louisiana approximately 75 miles east of Venice in 315 feet of water. We acquired our working interests in these blocks, which range from 50% to 100%, in a transaction with ConocoPhillips. 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 Cristellaria I. As of December 31, 2010, 12 wells have been drilled in this field, of which 10 were successful. Cumulative field production through 2010 is approximately 141 Bcfe gross. During December 2010, production from this field, net to our interest, averaged 10.2 MMcf of natural gas per day and 1,136 Bbls of oil per day, or 17.0 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 Chevron 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 75% to 100%. Cumulative field production through 2010 is approximately 703 Bcfe gross. During December 2010, production from this field, net to our interest, averaged 0.1 MMcf of natural gas per day and 262 Bbls of oil per day, or 1.7 MMcfe per day. We currently have rig interventions scheduled in 2011, which we expect will increase the production from this field.

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 2010 is approximately 797 Bcfe gross from eleven productive wells. The field has one processing platform and three independent structures. During December 2010, production from this field, net to our interest, averaged 3.7 MMcf of natural gas per day and 169 Bbls of oil per day, or 4.7 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, 2010, 75 wells have been drilled of which 57 have been successful. Cumulative field production through 2010 is approximately 552 Bcfe gross. We own a 100% working interest in the field and are the operator of the field. During December 2010, production from this field, net to our interest, averaged 1.9 MMcf of natural gas per day and 1,520 Bbls of oil per day, or 11.0 MMcfe per day.

Proved Reserves

Our estimated proved reserves at December 31, 2010 totaled 485.4 Bcfe as computed under the revised SEC requirements that were effective for periods ending on or after December 31, 2009. Approximately 81% of our proved reserves were classified as proved developed and 19% were classified as proved undeveloped. Classified by product, 53% of our proved reserves were natural gas and 47% were oil and natural gas liquids, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. Our proved reserves were estimated by an independent petroleum consultant, NSAI.

Our proved reserves as of December 31, 2010 are summarized below. These reserve amounts are consistent with filings we make with other federal agencies.

	As of December 31, 2010					
			Total Equivalent Reserves			
Classification of Proved Reserves	**Oil and NGLs (MMBbls)**	**Natural Gas (Bcf)**	**Natural Gas Equivalent (Bcfe) (1)**	**Barrel Equivalent (MMBoe) (1)**	**% of Total Proved**	**PV-10 (2) (In millions)**
Proved developed producing	14.8	147.7	236.6	39.4	49%	$ 888.0
Proved developed non-producing (3)	12.2	81.4	154.7	25.8	32%	493.3
Total proved developed	27.0	229.1	391.3	65.2	81%	1,381.3
Proved undeveloped	11.2	27.2	94.1	15.7	19%	510.0
Total proved (4)	38.2	256.3	485.4	80.9	100%	$1,891.3

(1) One billion cubic feet equivalent (Bcfe) and one million barrel equivalent (MMBoe) 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). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. Similarly, the price per barrel for oil and natural gas liquids may differ significantly from the price per Boe for natural gas.

(2) We refer to PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate. Neither PV-10 or PV-10 after ARO are financial measures prescribed under generally accepted accounting principles ("GAAP"); therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures are valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 after ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 after ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP.

The reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves at December 31, 2010 is as follows (in millions):

	At December 31, 2010
Present value of estimated future net revenues (PV-10)	$1,891.3
Present value of estimated ARO, discounted at 10%	(364.8)
PV-10 after ARO	1,526.5
Future income taxes, discounted at 10%	(347.4)
Standardized measure of discounted future net cash flows	$1,179.1

3) Includes approximately 29.6 Bcfe of reserves that were shut-in at December 31, 2010 due to two pipeline outages impacting several fields, including our Main Pass 108 field. We anticipate that the majority of these reserves will be reclassified to producing in 2011.

(4) In accordance with guidelines established by the SEC, our estimated proved reserves as of December 31, 2010 were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average commodity price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the year end December 31, 2010. Prices were adjusted by lease for quality, transportation, fees, energy content and regional price differentials. For oil and natural gas liquids, the average West Texas Intermediate posted price was used in the calculation and a net price of $75.96 per barrel was used in computing the amounts above. For natural gas, the average Henry Hub spot price was used in the calculation and a net price of $4.38 per MMcf was used in computing the amounts above. Such prices were held constant throughout the estimated lives of the reserves. Future production, development costs and ARO are based on year-end costs with no escalations.

Changes in Proved Reserves

Our total proved reserves increased to 485.4 Bcfe at December 31, 2010 from 371.0 Bcfe at December 31, 2009, primarily as a result of the acquisitions of properties from Shell and Total discussed in Item 1, *Business*. Proved reserves associated with the properties acquired from Shell and Total were 80.0 Bcfe and 65.6 Bcfe, respectively, and other smaller acquisitions increased reserves by 6.4 Bcfe as of December 31, 2010. Estimated proved reserves also increased 29.2 Bcfe due to extensions and discoveries resulting from our participation in the drilling of four successful exploratory wells and also increases resulting from well completions, recompletions and workovers. In addition, reserves increased from revisions of previous estimates by 20.2 Bcfe. Partially offsetting these increases were declines associated with production of 87.0 Bcfe. See Item 8 *Financial Statements – Note 21 – Supplemental Oil and Gas Disclosures* for additional information.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our estimated proved reserve information as of December 31, 2010 included in this Annual Report on Form 10-K was prepared by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The scope and results of their procedures are summarized in a letter included as an exhibit to this Annual Report on Form 10-K. The primary technical person at NSAI responsible for overseeing the preparation of the reserves estimates presented herein has B.S. and M.S. degrees in Civil Engineering and has been a Registered Professional Engineer in the State of Texas for 22 years and a member of the Society of Petroleum Engineers for over 26 years. He has over 33 years total experience in the oil and gas industry, with over 19 years of reservoir engineering experience. His areas of experience are the continental shelf and deepwater Gulf of Mexico, San Juan Basin, onshore and offshore Mexico, offshore Africa, and unconventional gas sources worldwide. NSAI has informed us that he meets or exceeds the education, training, and experience requirements set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates. Additionally, our senior management reviews any significant changes to our proved reserves on a quarterly basis.

Reserve Technologies

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our independent petroleum consultant employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- 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.

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.

Reporting of Oil and Natural 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, 2010 reserve report prepared by our independent petroleum consultant, natural gas liquids represented approximately 5% 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 natural gas liquids in the oil category using a ratio of 42 gallons/barrel. Prices for natural gas liquids in 2010 were approximately 44% lower on average than prices for equivalent volumes of oil. Natural gas liquids accounted for 17% of our combined reported production for oil, condensate and natural gas liquids combined. 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.

Development of Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2010, as estimated by our independent petroleum consultant, were 94.1 Bcfe. Future development costs associated with our proved undeveloped reserves at December 31, 2010 were estimated at $156.6 million. In 2010, we developed approximately 1% of our proved undeveloped reserves as of December 31, 2009, consisting of one gross (0.1 net) well and spent $0.9 million in 2010 with respect to our interest in this well. We believe that we will be able to develop all of the reserves classified as proved undeveloped at year end 2010 within the next five years.

More than 76% of our proved undeveloped reserves are concentrated in two fields; Ship Shoal 349, which is our Mahogany field, and our Main Pass 108 field. We have two development wells planned in each of those fields in 2011. We anticipate that one development well in each field planned for 2011 will reach its targeted depths by the end of the year in 2011 while the other two development wells may not reach total vertical depth until 2012. Any change in classification of reserves between proved developed and undeveloped is solely dependent on when such wells reach total vertical depth and any resulting production.

Acreage

The following summarizes gross and net developed and undeveloped acreage at December 31, 2010. 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	611,195	370,292	97,988	84,879	709,183	455,171
Deepwater	85,952	50,470	51,840	43,200	137,792	93,670
Total Offshore	697,147	420,762	149,828	128,079	846,975	548,841
Onshore	—	—	6,628	4,644	6,628	4,644
Total	697,147	420,762	156,456	132,723	853,603	553,485

Approximately 82% 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 156,456 of our gross acreage is undeveloped leasehold. Our rights to approximately 15% could expire in 2011, 1% in 2012, 25% in 2013, 24% in 2014 and 35% in 2015 and beyond, if not extended by exploration and production activities prior to the applicable lease expiration dates. In making decisions regarding our drilling activity for 2011 we will give consideration to our undeveloped leasehold that may expire in 2011 in order to retain the opportunity to exploit such acreage, based on the appropriate technical criteria, before expiration of the lease.

Certain non-producing oil and gas leases expired or were formally relinquished, which reduced our total gross and net acreage. These reductions were partially offset by additions from the property interests acquired from Total and Shell. Overall, our total gross and net acreage decreased 5.9% and 4.4%, respectively, from December 31, 2009.

Production

During 2010, our net production averaged approximately 238 MMcfe per day. Net production was deferred in 2010 at our Main Pass 108 field as a result of a pipeline outage beginning in June 2010 and continuing through year end. We estimate that as a result of this pipeline outage we have had approximately 4.9 Bcfe of production deferred during 2010. We currently expect production from the field to resume in the first half of 2011.

Production History

The following presents historical information about our produced oil and natural gas volumes from all of our producing fields over the past three fiscal years.

	Year Ended December 31,		
	2010	2009	2008
Net sales:			
Natural gas (Bcf)	44.7	51.6	56.1
Oil and NGLs (MMBbls)	7.1	7.2	7.0
Total natural gas equivalent (Bcfe) (1)	87.0	94.8	97.9

(1) Production decreased in 2010 primarily due to two pipeline outages impacting several fields, including our Main Pass 108 field, and divestitures completed in 2009, partially offset by the acquisition of properties from Total and Shell in 2010.

Refer to the descriptions of our ten largest fields earlier in Item 2 – *"Properties"* for historical information about our produced oil and natural gas volumes from our Ship Shoal 349 field and Viosca Knoll 783 field over the past three fiscal years, which have proved reserves comprising 15% or more of our total proved reserves. 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, 2010 in our productive oil and natural gas wells, including wells that were temporarily shut-in on that date primarily because of two pipeline outages impacting several fields, including our Main Pass 108 field. 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	99	86.5	116	96.6	215	183.1
Non-operated	60	21.2	90	18.3	150	39.5
	159	107.7	206	114.9	365	222.6

(1) Includes 5 gross (3.2 net) oil wells and 4 gross (2.9 net) gas wells with multiple completions.

The following table presents the number of wells included in the above table that were temporarily shut-in at December 31, 2010 due to the pipeline outages.

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	9	7.6	15	12.9	24	20.5
Non-operated	—	—	1	0.4	1	0.4
	9	7.6	16	13.3	25	20.9

Drilling Activity

During 2010, we participated in the drilling of six offshore and two onshore wells. The two onshore wells, which were both high risk/high potential exploration wells, were unsuccessful but five of the six offshore wells were successful. Of the five successful wells, four were exploration wells and one was a development well. All five of the successful wells were on the conventional shelf. We operate three of the five successful wells. As of December 31, 2010, we were in the process of drilling two onshore exploration wells in Southeast Texas and one offshore exploration well on the conventional shelf.

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, 2010, our capital expenditures for oil and natural gas properties and equipment of $415.7 million included $60.2 million for exploration activities, $77.2 million for development activities and $41.3 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,		
	2010	**2009**	**2008**
Gross Wells:			
Productive	1	2	2
Non-productive	—	1	—
	1	3	2
Net Wells:			
Productive	0.1	1.7	1.7
Non-productive	—	0.5	—
	0.1	2.2	1.7

Our success rates related to our gross development wells drilled during the years ended December 31, 2010, 2009 and 2008 were 100%, 67% and 100%, respectively.

Exploration Drilling

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Gross Wells:			
Productive	4	8	18
Non-productive	3	2	6
	7	10	24
Net Wells:			
Productive	3.1	5.9	12.3
Non-productive	1.7	1.3	4.4
	4.8	7.2	16.7

Our success rates related to our gross exploration wells drilled during the years ended December 31, 2010, 2009 and 2008 were 57%, 80% and 75%, respectively.

Current Drilling Activity

During the period beginning January 1, 2011 and ending February 25, 2011, we participated in the drilling of one gross (0.5 net) onshore exploratory well and one gross (1.0 net) offshore exploratory well, both of which were successful. We were in the process of drilling one gross (0.25 net) onshore exploratory well as of February 25, 2011.

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.

Executive Officers of the Registrant

The following lists our executive officers:

Name	Age	Position
Tracy W. Krohn	56	Founder, Chairman, Director and Chief Executive Officer
J.F. Freel	98	Founder, Chairman Emeritus, Director and Secretary
Jamie L. Vazquez	50	President
John D. Gibbons	57	Senior Vice President, Chief Financial Officer and Chief Accounting Officer
Stephen L. Schroeder	48	Senior Vice President and Chief Operating Officer
Jesus G. Melendrez	52	Senior Vice President and Chief Commercial Officer
Thomas F. Getten	63	Vice President, General Counsel and Assistant Secretary

Ages as of February 18, 2011.

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 as 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.

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. Prior to joining the Company, Mr. Gibbons was Senior Vice President and Chief Financial Officer of Westlake Chemical Corporation from March 2006 to February 2007. Prior to joining Westlake, Mr. Gibbons was with Valero Energy Corporation for 23 years, holding positions of increasing responsibility ending as Executive Vice President and Chief Financial 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.

Jesus G. Melendrez joined the Company in January 2011 as Senior Vice President and Chief Commercial Officer. From 2003 to 2010, Mr. Melendrez worked at Mariner Energy, Inc. and served in a variety of positions of increasing responsibility, culminating as Senior Vice President and Chief Commercial Officer and acting Chief Financial Officer and Treasurer. From February 2000 until July 2003, Mr. Melendrez was a Vice President of Enron North America Corp. in the Energy Capital Resources group, where he managed the group's portfolio of oil and gas investments.

Thomas F. Getten joined the Company in July 2006 as General Counsel. In August 2010, Mr. Getten was named Vice President, General Council and Assistant Secretary. Prior to joining the Company, Mr. Getten served as a partner with King, LeBlanc & Bland, P.L.L.C., a New Orleans law firm, since February 2001. From 1996 to December 2000, Mr. Getten served as Vice President, Secretary and General Counsel of Forcenergy, Inc. until its merger into Forest Oil Corporation.

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 the high and low sales price of our common stock as reported on the New York Stock Exchange.

	High	Low
2010		
First Quarter	$13.27	$ 8.15
Second Quarter	12.00	8.25
Third Quarter	10.83	8.41
Fourth Quarter	20.00	10.50
2009		
First Quarter	17.30	4.94
Second Quarter	12.10	5.80
Third Quarter	12.88	7.70
Fourth Quarter	14.87	9.78

As of February 25, 2011, there were 298 registered holders of our common stock.

Dividends

Under the Credit Agreement as amended, we are allowed to pay annual dividends or make share repurchases of up to $60 million per year if we are not in default. In addition, the indenture governing the 8.25% Senior Notes (the "Senior 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 Item 8 *Financial Statements – Note 7 – Long-Term Debt* for more information regarding our Credit Agreement and the indenture governing the Senior 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):

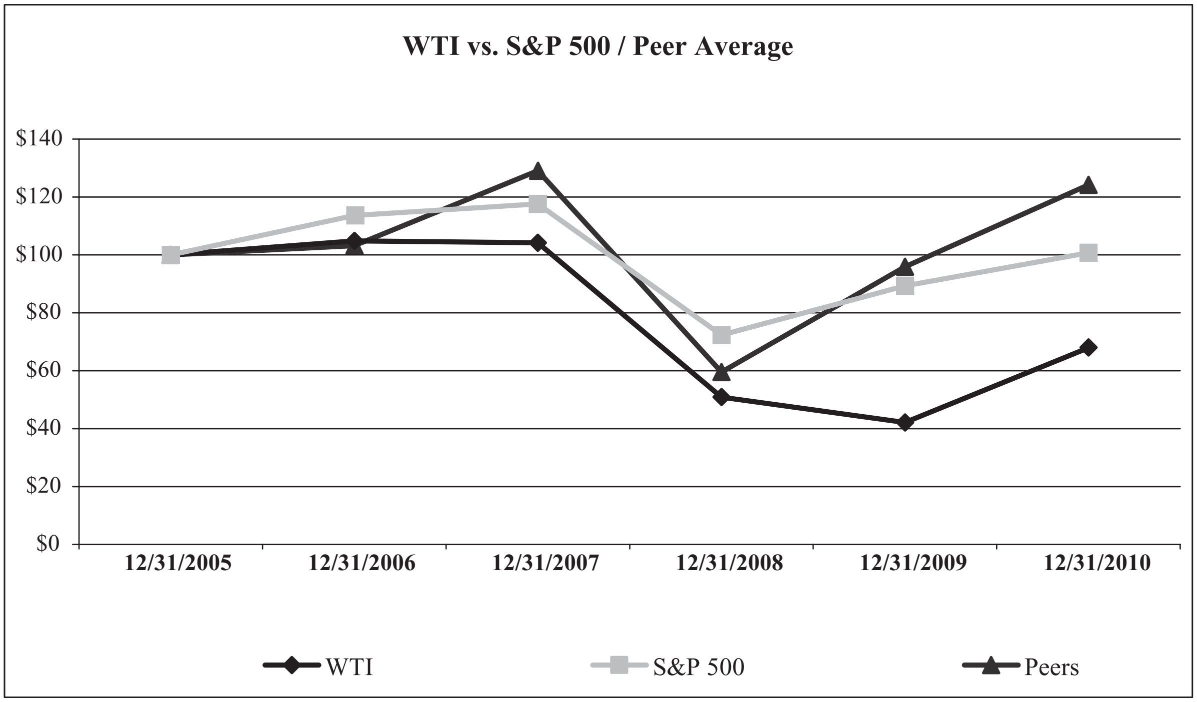
	Aggregate Dividends on Common Stock	Dividends per Share of Common Stock
2010		
First Quarter	$ 2,240	$0.03
Second Quarter	2,241	0.03
Third Quarter	2,986	0.04
Fourth Quarter (1)	52,142	0.70
2009		
First Quarter	2,289	0.03
Second Quarter	2,292	0.03
Third Quarter	2,292	0.03
Fourth Quarter	2,285	0.03

(1) Includes a regular dividend of $3.0 million ($0.04 per common share) and a special cash dividend of $49.2 million ($0.66 per common share).

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 and applicable debt agreement restrictions. On March 1, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on March 31, 2011 to shareholders of record on March 15, 2011.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 in our common stock and the reinvestment of all dividends thereafter. The information contained in the graph below is furnished and not filed, and is not incorporated by reference into any document that incorporates this Annual Report on Form 10-K by reference.



Our peer group is comprised of ATP Oil & Gas Corp., Cabot Oil & Gas Corp., Comstock Resources, Inc., Energy XXI (Bermuda) Limited, Forest Oil Corp., McMoRan Exploration Co., Newfield Exploration Co., Noble Energy, Inc., Plains Exploration & Production Co., Quicksilver Resources Inc., SM Energy Co., Stone Energy Corp., Venoco, Inc., and Whiting Petroleum Corp.

Issuer Purchases of Equity Securities

For the year ended December 31, 2010, we did not purchase any of our equity securities.

The following table sets forth information about shares delivered by employees during the quarter ended December 31, 2010 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
October 1, 2010 – October 31, 2010	N/A	N/A	N/A	N/A
November 1, 2010 – November 30, 2010	N/A	N/A	N/A	N/A
December 1, 2010 – December 31, 2010	142,268	$16.95	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 Item 8 *Financial Statements*.

	Year Ended December 31,				
	2010 (1)	2009 (2)	2008	2007	2006 (3)
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income (Loss) Information:					
Revenues:					
Natural gas	$203,533	$ 204,758	$ 527,352	$ 552,687	$ 427,839
Oil and NGLs	505,366	400,658	688,097	560,940	372,509
Other	(3,116)	5,580	160	122	118
Total revenues	705,783	610,996	1,215,609	1,113,749	800,466
Operating costs and expenses:					
Lease operating expenses (4)	169,670	203,922	229,747	234,758	113,993
Production taxes	1,194	1,544	8,827	5,921	1,556
Gathering and transportation	16,484	13,619	15,957	15,526	16,141
Depreciation, depletion and amortization	268,415	308,076	482,464	510,903	325,131
Asset retirement obligation accretion	25,685	34,461	39,312	22,007	12,496
Impairment of oil and natural gas properties (5)	—	218,871	1,182,758	—	—
General and administrative expenses (6)	53,290	42,990	47,225	38,853	37,778
Derivative (gain) loss (7)	4,256	7,372	16,464	36,532	(24,244)
Total costs and expenses	538,994	830,855	2,022,754	864,500	482,851
Operating income (loss)	166,789	(219,859)	(807,145)	249,249	317,615
Interest expense, net of amounts capitalized	37,706	40,087	34,709	37,088	17,180
Loss on extinguishment of debt (8)	—	2,926	—	2,806	—
Other income (9)	710	842	13,372	6,404	5,919
Income (loss) before income tax expense (benefit)	129,793	(262,030)	(828,482)	215,759	306,354
Income tax expense (benefit)	11,901	(74,111)	(269,663)	71,459	107,250
Net income (loss)	$117,892	$(187,919)	$ (558,819)	$ 144,300	$ 199,104
Earnings (loss) per common share					
Basic and diluted	$ 1.58	$ (2.51)	$ (7.36)	$ 1.89	$ 2.83
Dividends on common stock (10)	59,609	9,158	27,713	39,146	8,522
Cash dividends per common share (10)	0.80	0.12	0.36	0.51	0.12
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$464,772	$ 156,266	$ 882,496	$ 688,597	$ 571,589
Capital expenditures – oil and natural gas properties	415,653	276,134	774,879	361,235	1,650,747

	December 31,				
	2010	2009	2008	2007	2006
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Cash and cash equivalents	$ 28,655	$ 38,187	$ 357,552	$ 314,050	$ 39,235
Total assets	1,424,094	1,326,833	2,056,186	2,812,204	2,609,685
Long-term debt	450,000	450,000	653,172	654,764	684,997
Shareholders' equity	421,743	358,950	572,227	1,151,340	1,042,917

(1) In the second quarter of 2010, we acquired property interests from Total and, in the fourth quarter of 2010, we acquired property interests from Shell.

(2) In 2009, we sold one of our fields in Louisiana state waters and 36 non-core oil and natural gas fields in the Gulf of Mexico.

(3) In 2006, we acquired working interests in approximately 100 oil and natural gas fields on 242 offshore blocks located in the Gulf of Mexico from Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") by merger.

(4) Included in lease operating expenses for the year ended December 31, 2010 is a $11.7 million net reduction to cost due to insurance reimbursements being in excess of costs for hurricane-related repairs. For the years ended December 31, 2009, 2008, 2007 and 2006, net charges to costs were $18.4 million, $17.7 million, $18.5 million and $0.5 million, respectively, due to costs being in excess of insurance reimbursements for hurricane-related repairs.

(5) The carrying amount of our oil and natural gas properties was written down by $218.9 million in 2009 and $1.2 billion in 2008 through the application of the full cost ceiling limitation due to lower oil and natural gas prices. No such write downs were required during the other years presented.

(6) General and administrative expenses ("G&A") related to our long-term incentive compensation plans were $13.3 million, $7.0 million, $11.9 million, $8.1 million, and $8.7 million in 2010, 2009, 2008, 2007 and 2006, respectively.

(7) Derivative (gain) loss consists of both realized and unrealized gains and losses for commodity and interest derivatives. For the years 2010, 2009, 2008, 2007 and 2006, we had net gains or net losses related to commodity derivatives of $4.0 million loss, $5.6 million loss, $10.0 million loss, $33.0 million loss and $24.2 million gain, respectively. For the years 2010, 2009, 2008, 2007 and 2006, we had net losses related to interest rate derivatives of $0.3 million, $1.8 million, $6.5 million, $3.5 million and $0.0 million, respectively. See Item 8 *Financial Statements – Note 6 – Derivative Financial* for more information.

(8) In 2009, we wrote off $2.9 million of deferred financing costs related to the early repayment of our previously outstanding term loan facility ("Tranche B"). In 2007, we wrote off of $2.8 million of deferred financing costs related to the early repayment of our Tranche A term loan.

(9) Consists primarily of interest income.

(10) The years 2010, 2008 and 2007 include a special dividend of $49.2 million ($0.66 per share), $20.8 million ($0.39 per share) and $30.0 million ($0.27 per share), respectively. Years 2009 and 2006 did not have a special dividend.

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 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 estimated proved 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 Item 8 *Financial Statements*.

	December 31,				
	2010	2009	2008	2007	2006
Reserve Data:					
Estimated net proved reserves (1) (2):					
Natural gas (Bcf)	256.3	165.8	227.9	332.8	401.2
Oil and NGLs (MMBbls)	38.2	34.2	43.9	51.0	55.7
Total natural gas equivalent (Bcfe)	485.4	371.0	491.1	638.8	735.2
Proved developed producing (Bcfe)	236.6	162.5	148.6	224.1	225.3
Proved developed non-producing (Bcfe) (3)	154.7	121.0	185.5	171.2	253.6
Total proved developed (Bcfe)	391.3	283.5	334.1	395.3	478.9
Proved undeveloped (Bcfe)	94.1	87.5	157.0	243.5	256.3
Proved developed reserves as a percentage of proved reserves	80.6%	76.4%	68.0%	61.9%	65.1%
Reserve additions (reductions) (Bcfe):					
Revisions (4)	20.3	(25.5)	(157.5)	(18.7)	(13.1)
Extensions and discoveries	29.1	23.4	47.2	48.4	109.3
Purchases of minerals in place	152.0	0.7	60.5	1.4	246.7
Sales of minerals in place	—	(23.9)	—	(1.0)	—
Production	(87.0)	(94.8)	(97.9)	(126.5)	(99.2)
Net reserve additions (reductions)	114.4	(120.1)	(147.7)	(96.4)	243.7

(1) Estimated reserves as of December 31, 2010 and 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December of the respective year in accordance with SEC guidelines. Estimated reserves as of December 31, 2008, 2007, and 2006 are based on end-of-period commodity prices in accordance with the previous SEC guidelines in effect on those respective dates.

(2) 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). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

(3) Approximately 29.6 Bcfe of reserves were shut-in at December 31, 2010 due to two pipeline outages impacting several fields, including our Main Pass 108 field. Approximately 1.7 Bcfe and 53.9 Bcfe of reserves were shut-in at December 31, 2009 and 2008, respectively, because of damage caused by Hurricane Ike in September 2008. Approximately 20.2 Bcfe of reserves were shut-in at December 31, 2006 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.

(4) Revisions for 2009 included decreases attributable to the changes in reserve reporting requirements for oil and natural gas companies enacted by the SEC, which became effective for us on December 31, 2009. The revised rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
Operating Data:					
Net sales:					
Natural gas (Bcf)	44.7	51.6	56.1	76.7	60.4
Oil and NGLs (MMBbls)	7.1	7.2	7.0	8.3	6.5
Total natural gas equivalent (Bcfe) (1)	87.0	94.8	97.9	126.5	99.2
Average daily equivalent sales (MMcfe/d)	238.4	259.7	267.5	346.7	271.7
Average realized sales prices (Unhedged):					
Natural gas ($/Mcf)	$ 4.55	$ 3.97	$ 9.40	$ 7.20	$ 7.08
Oil and NGLs($/Bbl)	71.65	55.67	98.72	67.58	57.70
Natural gas equivalent ($/Mcfe)	8.15	6.39	12.42	8.80	8.07
Average realized sales prices (Hedged) (2):					
Natural gas ($/Mcf)	$ 4.71	$ 3.96	$ 9.42	$ 7.28	$ 7.23
Oil and NGLs($/Bbl)	71.42	55.67	94.67	67.01	57.97
Natural gas equivalent ($/Mcfe)	8.21	6.38	12.14	8.81	8.18
Average per Mcfe ($/Mcfe):					
Lease operating expenses	$ 1.95	$ 2.15	$ 2.35	$ 1.86	$ 1.15
Gathering and transportation costs	0.19	0.14	0.16	0.12	0.16
Production costs	2.14	2.29	2.51	1.98	1.31
Production taxes	0.01	0.02	0.09	0.05	0.02
Depreciation, depletion, amortization and accretion	3.38	3.61	5.33	4.21	3.40
General and administrative expenses	0.61	0.45	0.48	0.31	0.38
	$ 6.14	$ 6.37	$ 8.41	$ 6.55	$ 5.11
Total number of wells drilled (gross)	8	13	26	9	34
Total number of productive wells drilled (gross)	5	10	20	8	27

(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). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

(2) Data for all years presented includes the effects of gains and losses on commodity derivative contracts, none of which qualified for hedge accounting.

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 Item 8 *Financial Statements*. 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 primarily in the Gulf of Mexico. We have grown through acquisitions, exploitation and exploration and currently hold working interests in approximately 67 producing fields in federal and state waters. We operate wells accounting for approximately 73% 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

0.9 million gross acres (0.6 million net acres) spanning primarily across the outer continental shelf off the coasts of Louisiana, Texas, Mississippi and Alabama and minor holdings onshore. We own interests in approximately 267 structures, 159 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 strive to grow our reserves through acquisitions and our 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.

During the year 2010, we closed on two major acquisition transactions. On April 7, 2010, we entered into a PSA with Total and on April 30, 2010, through Energy VI, we acquired all of Total's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $150 million, subject to customary closing adjustments, with an effective date of January 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $6.3 million. The properties acquired from Total are producing interests with future development potential, and include a 100% working interest in the Matterhorn field and a 64% working interest in the Virgo field. The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $115.0 million. This acquisition was funded with cash on hand.

On November 3, 2010, we entered into an APA with Shell and on November 4, 2010, through Energy VI, we acquired all of Shell's interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $138.0 million, subject to customary closing adjustments and preferential right elections, with an effective date of September 1, 2010 and entered into a letter of intent to acquire a fourth property described below. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $18.0 million. The properties acquired from Shell are producing interests with future development potential, and include a 70% working interest in the Tahoe field, a 100% working interest in the Southeast Tahoe field and a 6.25% of 8/8ths overriding royalty interest in the Droshky field. The transaction closed on November 4, 2010 with our wholly-owned subsidiary, Energy VI as purchaser. The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $121.9 million. Such amount is still subject to further adjustments upon final settlement. This acquisition was funded with cash on hand. See Item 8 *Financial Statements – Note 2 – Acquisitions and Divestitures* for additional information on completed acquisitions in 2010.

Also, on November 3, 2010, we entered into a letter of intent with Shell to acquire its 64.3% working interest in a shallow water producing property in the Gulf of Mexico along with certain associated assets. The letter of intent provides for a purchase price of $55.0 million, subject to customary closing adjustments, with an effective date of September 1, 2010. In addition, the ARO for plugging and abandonment with respect to this interest is estimated at $12.9 million. The transaction requires approval of a state regulatory agency and resolution of various other items. We expect to fund the acquisition with cash on hand and borrowings under our revolving loan facility.

From time to time, we sell various properties that we determine are no longer part of our business strategy. We are currently marketing certain properties that we consider non-core.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil and natural gas production and the price that we receive for such production. In 2010, our production volume was comprised of approximately 49% oil, condensate and natural gas liquids and 51% natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. During 2010, we sold an average of approximately 122 MMcf of natural gas per day and approximately 19,000 Bbls of oil per day, or a combined rate of 238 MMcfe per day. Most of the production that was affected by Hurricane Ike in 2008 and 2009 was restored by 2010. One major field, Main Pass 108, has had production curtailed since June 2010 due to the third-party pipeline outage and we anticipate production from the field to resume in the first half of 2011.

Prices for oil and natural gas continued to be volatile in 2010. Using the first-day-of-the-month West Texas Intermediate posted price, the average price for oil was $75.96 per barrel for 2010, representing an increase of 31.8% from $57.65 for 2009. The price for oil during 2010 ranged from a low of $69.00 per barrel to a high of $83.25 per barrel and during 2009 ranged from $38.25 to $74.75 per barrel. During the year ended December 31, 2010, our average realized sales price for oil increased by 28.7%. During the first half of 2009, prices and the economy were affected by the financial crisis and economic recession that affected much of the world and continues today in parts of the world. Oil prices, along with many areas of the global economy, recovered in the second half of 2009 and were higher in 2010 on an average price basis. Long-term forecasts for oil demand, and therefore global oil prices, continue to be favorable in several key growing markets, specifically China and India.

Natural gas prices are much more affected by domestic issues, such as supply, local demand issues and domestic economic conditions. Using the first-day-of-the-month Henry Hub spot price, the average price for natural gas was $4.38 per MMBtu for 2010, representing an increase of 13.2% from $3.87 per MMBtu for 2009. The price for natural gas in 2010 ranged from a low of $3.35 per MMBtu to a high of $5.84 per MMBtu and the range in 2009 was $2.41 to $5.63 per MMBtu. During the year ended December 31, 2010, the average realized sales price of our natural gas increased 14.6%. We are expecting continued weakness in natural gas prices unless demand for natural gas increases as a result of a strong economic recovery, drilling activity subsides dramatically or forced production shut-ins occur. There is also a risk that, as a result of successful exploration and development activities in the shale areas coupled with the availability of increasing amounts of liquefied natural gas, increased supplies of natural gas will offset or mitigate the impact of any natural gas shut-ins or demand increases resulting from improved economic conditions. According to industry sources, the rig count for horizontal drilling rigs, used primarily in the shale formation areas such as Louisiana, Arkansas, Texas, North Dakota and Pennsylvania, has reached or exceeded record levels. Natural gas production and supply continues to exceed demand. Onshore natural gas producers have continued to drill in attempts to yield production sufficient to preserve existing leases, while such production has historically been hedged at prices significantly higher than current levels, which allowed funding of projects that continue to increase supply to an already oversupplied market. Seasonal weather conditions also impact the demand for and price of natural gas.

Historically, West Texas Intermediate crude oil has traded at a slight premium to most other crude oils because of its relatively low sulfur content and high gravity. At times over the last several years, this relationship has changed because of various factors, such as refinery fires or declines in domestic crude oil demand similar to those experienced in 2009 resulting from the economic recession that led to significant discounts for West Texas Intermediate crude relative to other crudes. During the first two months of 2011, the spread between West Texas Intermediate crude and other crudes has widened dramatically; for example, on February 11, 2011, the premium spread between Light Louisiana Sweet crude and West Texas Intermediate crude was in excess of $17 per barrel. During January 2011, over 65% of our crude consisted of Light Louisiana Sweet crude or Heavy Louisiana Sweet crude, which has also received a significant premium spread relative to West Texas Intermediate crude thus far in 2011. Accordingly, we may continue to experience premiums to West Texas Intermediate crude in our future sales of crude oil until such time as factors cause changes in the marketplace for the prices of crude oil. The crude oil market has historically corrected itself relatively quickly when the spreads widen as they have done so far during 2011, and we cannot predict with any certainty how long such pricing conditions will last.

In 2010, we recorded no ceiling test impairment but in 2009, we recorded a $218.9 million ceiling test impairment due to declines in prices. Declines in oil and natural gas prices after December 31, 2010 could result in ceiling test impairments of the carrying value of our oil and natural gas properties, issues with financial ratio debt compliance, and a reduction of the borrowing base associated with our credit agreement. Such declines may limit the willingness of financial institutions and investors to provide borrowings or capital to us and others in the oil and natural gas industry.

Our operating costs include the expense of operating our wells, platforms and other infrastructure primarily 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.

Our operations are exposed to potential damage from hurricanes and we obtain insurance to reduce our financial exposure risk. We incurred substantial costs in 2008, 2009 and 2010 for hurricane related damage from 2008 and expect to incur costs through 2012 to complete plugging and abandonment work primarily related to three toppled platforms. We received reimbursements from our insurance carrier in 2009 and 2010 and expect to receive additional reimbursements for costs incurred in future periods as costs incurred to date have not exceeded policy limits. See *Liquidity and Capital Resources* below and Item 8 *Financial Statements – Note 3 – Hurricane Remediation and Insurance Claims* for additional information.

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 ARO generally increase as we drill wells in deeper parts of the continental shelf, in the deepwater and onshore. We generally do not pre-fund our ARO. We estimated the liability related to our ARO at $391.3 million as of December 31, 2010. Inherent in the present value calculation of our liability are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in ultra deep water in the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced loss of life and economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, there have been many proposals by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. Beginning in May 2010, the BOEMRE issued a series of NTLs and operators implementing a six-month moratorium on drilling activities in federal offshore waters and imposing a variety of new safety measures and permitting requirements.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued by the BOEMRE, there have been numerous additional NTLs and additional proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and oil spill that could affect our operations and cause us to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations in the Gulf of Mexico by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, and, further, could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf of Mexico more difficult, more time consuming, and more costly. For example, a variety of amendments to the OPA have been proposed in response to the Deepwater Horizon incident. OPA and regulations adopted pursuant to OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the OCS, which includes the Gulf of Mexico where we have substantial offshore operations. OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to $150 million in certain situations. Legislation has been proposed in Congress to amend OPA to increase the minimum level of financial responsibility to $300 million or more. If OPA is amended to increase the minimum level of financial responsibility to $300 million, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by OPA, we may be forced to sell our properties or operations located on the OCS or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased.

Subsequent to the BP Deepwater Horizon incident in the U.S. Gulf of Mexico, the BOEMRE issued a series of NTLs imposing new requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

As a result of the issuance of these NTLs and lack of detail therein, BOEMRE has been taking much longer to review and approve permits for new wells. Due to the extremely slow pace of permit review and approval, various industry sources have determined that BOEMRE may take six months or longer to approve applications for drilling permits that were previously approved in less than 30 days. The NTLs also increase the cost of preparing each permit application and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS.

In addition, the BOEMRE issued NTL No. 2010-G05 dated effective October 15, 2010 that establishes a more stringent regimen for the timely decommissioning of what is known as “idle iron” – wells, platforms and pipelines that are no longer producing or serving exploration or support functions related to an operator’s lease – in the Gulf of Mexico. The recently issued NTL sets forth more stringent standards for decommissioning timing requirements by applying the requirement that any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years. Plugging or abandonment of wells may be delayed by two years if all of the well’s hydrocarbon and sulphur zones are appropriately isolated. Similarly, platforms or other facilities that are no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to historical decommissioning efforts may serve to increase, perhaps materially, our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future ARO required to meet such increased costs. For the year 2010, we increased our estimate of ARO by $18.7 million based on our expected acceleration in timing for such obligations as a result of implementing this NTL. (For additional details, refer to Item 8 *Financial Statements – Note 5 – Asset Retirement Obligations.*) However, the potential increase in decommissioning activity in the Gulf of Mexico over the next few years as a result of the NTL could likely result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related ARO.

Results of Operations

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenues. Revenues increased $94.8 million, or 15.5%, to $705.8 million for the year ended December 31, 2010 compared to 2009. Oil revenues increased $104.7 million, natural gas revenues decreased $1.2 million and other revenues decreased $8.7 million compared to 2009. The oil revenue increase was caused by a 28.7% increase in the average realized oil price to $71.65 per barrel in 2010 from $55.67 per barrel in 2009, partially offset by a 1.4% decrease in sales volumes to 7.1 MMBbls in 2010 from 7.2 MMBbls in 2009. The sales volume decrease for oil was primarily attributable to property divestitures in 2009, partially offset by increases associated with the Matterhorn field we purchased in the second quarter of 2010. The natural gas revenue decrease resulted from a 13.4% decrease in sales volumes to 44.7 Bcf in 2010 from 51.6 Bcf in 2009, partially offset by a 14.6% increase in the average realized natural gas sales price to $4.55 per Mcf in 2010 from $3.97 per Mcf in 2009. The sales volume decrease for natural gas is primarily attributable to production shut in at our Main Pass 108 field as a result of a pipeline outage that began in June 2010 and property divestitures in 2009, partially offset by volumes from the properties acquired from Total and Shell in 2010. The decrease in other revenues was primarily attributable to reversing $4.7 million originally recorded in 2009 as this amount relates to the disallowance by the BOEMRE of royalty relief for transportation of deepwater production through our subsea pipeline system. We are contesting this BOEMRE adjustment. For additional information, see Item 8 *Financial Statements – Note 18 – Contingencies.*

Lease operating expenses. Lease operating expenses decreased to $1.95 per Mcfe in 2010 from $2.15 per Mcfe in 2009. On a nominal basis, lease operating expenses decreased $34.3 million to $169.7 million in 2010 compared to the prior year. On a component basis, hurricane remediation costs and insurance claims, net, base lease operating expenses and insurance premiums decreased $30.1 million, $17.8 million and $0.8 million, respectively, while workover expenses and facilities expense increased $9.8 million and $4.8 million, respectively. Hurricane remediation costs and insurance claims, net, decreased due to insurance reimbursements being in excess of cost incurred for 2010. Lease operating expenses will be offset in future periods to the extent that hurricane remediation costs are recovered under our insurance policies. The decrease in base lease operating expenses primarily reflects decreases attributable to property divestitures during 2009, partially offset by increases associated with operating the properties acquired in 2010 from Total and Shell. The decrease in insurance expense is attributable to lower insurance premiums following the renewal of our insurance policies covering well control and hurricane damage. The increase in workover expense is related to three separate workover projects that required the use of rigs to perform the activity. The increase in facilities expense is primarily attributable to repairs to newly acquired properties, repairs to pipelines and compressors, and blast and paint work.

Production taxes. Production taxes decreased $0.4 million to $1.2 million in 2010 primarily due to property divestitures in 2009. Most of our production is from federal waters, where there are no production taxes.

Gathering and transportation costs. Gathering and transportation costs increased $2.9 million to $16.5 million in 2010 primarily due to costs associated with operating the properties acquired in 2010 from Total and Shell, partially offset by property divestitures that occurred in 2009.

Depreciation, depletion, amortization and accretion ("DD&A"). DD&A decreased to $294.1 million in 2010 from $342.5 million in 2009. DD&A decreased primarily due to lower production of oil and natural gas of 8.2% on a Mcfe basis. On a per Mcfe basis, DD&A was $3.38 in 2010 compared to $3.61 in 2009. The rate per Mcfe is lower primarily due to the reserves acquired from Total and Shell and the property divestitures in 2009. Our total proved reserves as of December 31, 2010 were 485.4 Bcfe, which was an increase of 30.8% compared to 2009. The increase is primarily due to the properties acquired from Total and Shell.

Impairment of oil and natural gas properties. In 2010, we did not have a ceiling test impairment but in the first quarter of 2009, we recorded a ceiling test impairment of our oil and natural gas properties of $218.9 million. This write down resulted from the application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of a further decline in natural gas prices at March 31, 2009 as compared to December 31, 2008. For a more detailed discussion of the ceiling test, refer to Item 8 *Financial Statements – Note 1 – Significant Accounting Policies*.

General and administrative expenses. G&A increased to $53.3 million in 2010 from $43.0 million in 2009, primarily due to higher incentive compensation and reductions in billings to joint-interest parties attributable to certain capital projects. Incentive compensation increased due to the Company's improved financial and operational performance in 2010 and the implementation of a new performance based incentive compensation plan. In 2009, no awards were granted for 2009 performance. On a per Mcfe basis, G&A was $0.61 per Mcfe for 2010, compared to $0.45 per Mcfe for 2009. See Item 8 *Financial Statements – Note 10 – Incentive Compensation Plan for more information.*

Derivative loss. For 2010, our derivative loss of $4.3 million consisted of a loss of $4.0 million for our commodity derivatives and a loss of $0.3 million for our interest rate swap. For 2009, our derivative loss of $7.4 million consisted of a loss of $5.6 million for our commodity derivatives and a loss of $1.8 million for our interest rate swap. Gains and losses are recorded based on the change in the fair values of the financial instruments. For additional details about our derivatives, refer to Item 8 *Financial Statements – Note 6 – Derivative Financial Instruments*.

Interest expense. Interest expense incurred decreased to $43.1 million for 2010 from $46.7 million in 2009 primarily due to lower interest rates and lower debt outstanding during 2010. During 2010 and 2009, $5.4 million and $6.7 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Loss on extinguishment of debt. In 2010, no loss on extinguishment of debt was incurred. In May 2009, we repaid the Tranche B term loan facility in full with borrowings under our revolving loan facility. As a result, in 2009 we recorded a loss of $2.9 million related to the write-off of deferred financing costs and other related incidental costs.

Interest income. Interest income decreased to $0.7 million for 2010 from $0.8 million in 2009 mainly due to lower average daily cash balances and a reduction in market interest rates received on invested cash in 2010.

Income tax expense/benefit. Income tax expense increased to $11.9 million in 2010 from an income tax benefit of $74.1 million for 2009. Our effective tax rate for 2010 was approximately 9.2% and primarily reflects a reduction in our valuation allowance against our deferred tax assets and the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code. Taxable income in 2010 allowed us to reverse all of our previously recorded valuation allowance. This reduction in our valuation allowance will not recur in 2011, and, as a result, we expect our effective tax rate during 2011 will approach the statutory rate of 35%. For 2009, the income tax benefit resulted from a pre-tax loss. Our effective tax rate for 2009 was approximately 28.3% and primarily reflected the effect of a change in law to increase the carryback period and a valuation allowance for our deferred tax assets.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenues. Revenues decreased $604.6 million, or 49.7%, to $611.0 million for the year ended December 31, 2009 compared to 2008. Oil revenues decreased $287.4 million, natural gas revenues decreased $322.6 million and other revenues increased $5.4 million compared to 2008. The oil revenue decrease was caused by a 43.6% decrease in the average realized oil price to $55.67 per barrel in 2009 from $98.72 per barrel in 2008, partially offset by a 2.9% increase in sales volumes. The natural gas revenue decrease resulted from a 57.8% decrease in the average realized natural gas price to $3.97 per Mcf in 2009 from $9.40 per Mcf in 2008 and an 8.0% decrease in sales volumes. The sales volume increase for oil is primarily attributable to the startup of production at our Green Canyon 646 field ("Daniel Boone") in September 2009. However, sales volumes for oil and natural gas were negatively affected in 2009 by the continued deferral of production caused by downtime experienced by third party pipelines and processing facilities damaged by Hurricane Ike in 2008, the sale of one of our fields in Louisiana state waters in the second quarter of 2009, the sale of 36 non-core oil and natural gas fields in the fourth quarter of 2009 and natural reservoir declines. During 2009, production of approximately 24 MMcfe per day, on average, remained shut-in due to hurricane damage. Production of approximately 9 MMcfe per day was shut-in due to hurricane damage and the majority of this production was reestablished in 2010. The increase in other revenues primarily relates to allowable reductions of cash payments for royalties owed to the BOEMRE for transportation of its royalty share of our deepwater production through our subsea pipeline systems.

Lease operating expenses. Lease operating expenses, which include base lease operating expenses, insurance costs, workovers and maintenance on our facilities, decreased to $2.15 per Mcfe in 2009 from $2.35 per Mcfe in 2008. On a nominal basis, lease operating expenses decreased $25.8 million to $203.9 million in 2009 compared to 2008. The decrease is attributable to decreases in base lease operating expenses and facility expenditures of $23.4 million and $10.4 million, respectively. Partially offsetting these decreases were increases in insurance costs and workovers of $4.0 million and $3.3 million, respectively. The decrease in base lease operating expenses primarily reflects lower overall service and supply costs and the sale of certain non-core properties as described above. The decrease in facility expenditures relates to several projects that were completed in 2008 that did not recur in 2009. Included in lease operating expenses for 2009 and 2008 are $18.4 million and $17.7 million, respectively, of hurricane remediation costs related to Hurricanes Ike and Gustav that were either not yet approved by our insurance underwriters' adjuster or were not covered by insurance. Lease operating expenses will be offset in future periods to the extent that these costs are recovered under our insurance policies.

Production taxes. Production taxes decreased $7.3 million to $1.5 million in 2009 primarily due to the sale of one of our fields in Louisiana state waters in the second quarter of 2009, lower production from fields in state waters of Texas and Louisiana and lower realized prices on sales of our oil and natural gas in 2009. Most of our production is from federal waters, where there are no production taxes.

Gathering and transportation costs. Gathering and transportation costs decreased $2.3 million to $13.6 million in 2009 primarily due to the sale of one of our fields in Louisiana state waters in the second quarter of 2009 and the sale of 36 non-core oil and natural gas fields in the fourth quarter of 2009.

Depreciation, depletion, amortization and accretion. DD&A decreased to $342.5 million in 2009 from $521.8 million in 2008. The decrease is primarily attributable to a lower depreciable base resulting from ceiling test impairments of $1.2 billion and $218.9 million in 2008 and 2009, respectively, and a net reduction of our ARO of $134.5 million primarily from the sale of certain assets and revisions to our estimates, partially offset by lower oil and natural gas reserves, compared to 2008. Total proved reserves decreased 120.1 Bcfe to 371.0 Bcfe at December 31, 2009 from 491.1 Bcfe at December 31, 2008, for a net reduction of 24.5%. Approximately 48.3 Bcfe of the reduction in our total proved reserves in 2009 is attributable to the new reserve reporting requirements for oil and natural gas companies enacted by the SEC and the Financial Accounting Standards Board ("FASB"), which became effective for annual reporting periods ending on or after December 31, 2009. As discussed earlier, the reduction in our total proved reserves associated with the new reserve reporting requirements resulted from the use of 12-month average commodity prices instead of end-of-period commodity prices in estimating our quantities of proved oil and natural gas reserves, as well as the removal of certain proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. The impact on our DD&A for 2009 related to the adoption of the new reserve reporting requirements was an approximate $7.6 million increase in DD&A. On a per Mcfe basis, DD&A was $3.61 for the year ended December 31, 2009, compared to $5.33 for the same period in 2008.

Impairment of oil and natural gas properties. At March 31, 2009, we recorded a ceiling test impairment of our oil and natural gas properties of $218.9 million through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of a further decline in natural gas prices at March 31, 2009 as compared to December 31, 2008. 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, primarily as a result of the significant decline in both oil and natural gas prices as of December 31, 2008. For a more detailed discussion of the ceiling test, refer to *Critical Accounting Policies – Impairment of oil and natural gas properties* below.

General and administrative expenses. G&A decreased to $43.0 million in 2009 from $47.2 million in 2008 primarily due to lower incentive compensation and travel expenses, partially offset by reduced overhead charges billed to joint operators. G&A expenses related to our long-term incentive compensation plans were $7.0 million and $11.9 million in the years 2009 and 2008, respectively. On a per Mcfe basis, G&A was $0.45 per Mcfe for the year 2009, compared to $0.48 per Mcfe for the year 2008.

Derivative loss. For the year 2009, our derivative loss of $7.4 million consisted of a loss of $5.6 million for our commodity derivatives and a loss of $1.8 million for our interest rate swap. For the year 2008, our derivative loss of $16.5 million consisted of a loss of $10.0 million for our commodity derivative and a loss of $6.5 million for our interest rate swap. Gains and losses are recorded based on the change in the fair values of the financial instruments.

Interest expense. Interest expense incurred decreased to $46.7 million for the year 2009 from $54.0 million in the year 2008 primarily due to lower interest rates and lower debt outstanding during 2009. During 2009 and 2008, $6.7 million and $19.3 million, respectively, of interest was capitalized to unevaluated oil and gas properties.

Loss on extinguishment of debt. In May 2009, we repaid the Tranche B term loan facility in full with borrowings under our revolving loan facility. As a result, in 2009 we recorded a loss of $2.9 million related to the write-off of deferred financing costs and other related incidental costs.

Interest income. Interest income decreased to $0.8 million for the year 2009 from $13.4 million in the year 2008 mainly due to lower average daily cash balances and a reduction in market interest rates received on invested cash in 2009.

Income tax expense/benefit. An income tax benefit of $74.1 million and $269.7 million was recorded in 2009 and 2008, respectively, primarily as a result of a net operating loss for tax purposes in each of those years. As described above, in 2009 and 2008 we recorded an impairment of our oil and natural gas properties of $218.9 million and $1.2 billion, respectively. On November 6, 2009, the Worker, Homeownership and Business Assistance Act of 2009 was signed into law. A provision of this act provides an election to increase the carryback period for applicable net operating losses up to five years from two years. A tax benefit of $38.4 million was recorded during the fourth quarter of 2009 as a result of this legislation. The effective tax rate of 28.3% for 2009 includes the federal statutory rate of 35.0%, reduced primarily by the effect of a recapture of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code related to net operating loss carrybacks, as well as the incremental current period effect of a change in our valuation allowance for our deferred tax assets. 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.

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 and bank borrowings. 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 increased to $464.8 million for 2010 compared to $156.3 million for 2009. The substantial increase between periods was due to three primary items. First, our oil and natural gas revenues increased $94.8 million primarily due to our combined average realized sales price being 27.5% higher in the 2010, which more than offset the 8.2% reduction in production. Second, in 2010, we received refunds of federal income taxes paid in prior years totaling $99.8 million, consisting primarily of carrybacks of net operating losses generated in 2009 and 2008. Third, in 2010, reimbursements from our insurance policies related to hurricane damage were $65.5 million compared to hurricane related costs for remediation, plugging and abandonment of $36.0 million, resulting in a net cash inflow of $29.5 million. In 2009, hurricane related costs for remediation, plugging and abandonment were $77.3 million compare to reimbursements of $48.8 million resulting in a net cash outflow of $28.5 million. Also of note, our operating expenses, including insurance premiums, were lower in 2010.

Net cash used in investing activities was $415.0 million and $237.7 million for 2010 and 2009, respectively, which primarily represents our investments in oil and natural gas properties. Included in 2010 are $115.0 million for the acquisition of the properties from Total and $121.9 million for the acquisition of the properties from Shell compared to minor acquisition outlays in 2009. Exploration and development investments were $137.4 million and $252.7 million for 2010 and 2009, respectively. Sales of assets in 2010 were minor compared to receiving $32.2 million for asset sales in 2009.

Net cash used in financing activities was $59.3 million and $237.9 million for 2010 and 2009, respectively. In 2010, we paid regular and special dividends of $59.6 million compared to only a normal dividend in 2009 of $9.2 million. Repayments of long-term debt of $205.4 million were made in 2009 while 2010 did not have any principal payments on long-term debt.

At December 31, 2010, we had a cash balance of $28.7 million and we had $405.1 million of undrawn capacity available under the revolving loan facility. 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, 2010, we were in compliance with such financial covenants. See below *Credit agreements and long-term debt* and Item 8 *Financial Statements – Note 7 – Long-term debt* for more information regarding our Credit Agreement. We believe that cash provided by operations, borrowings available under our revolving loan facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements.

From time to time, 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 revolving loan facility. As of December 31, 2010, our derivative instruments outstanding consisted of commodity option contracts relating to approximately 1.9 MMBbls and 1.1 MMBbls of our anticipated production for the calendar years 2011 and 2012, respectively. We did not have any interest rate derivatives as of December 31, 2010. For additional details about our derivatives, refer to Item 7A *Quantitative and Qualitative Disclosures About Market Risk* and Item 8 *Financial Statements – Note 6 – Derivative Financial Instruments*.

Hurricane Remediation and Insurance Claims. 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. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) 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.

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters' adjuster. Claims that have been processed in this manner have been paid on a timely basis.

In 2010, 2009 and 2008 we have received cash of $65.5 million, $48.8 million and $5.8 million, respectively, from our insurance carrier related to Hurricane Ike claims and have recorded $1.0 million of insurance receivables as of December 31, 2010 for claims that have been submitted and approved for payment. We have recorded in ARO an estimate of $72.5 million for additional costs to be incurred related to Hurricane Ike and we estimate that this work will be completed by the end of 2012. We expect to receive reimbursement for a portion of these costs from our insurance carrier once the costs are incurred, claims are processed and payments are approved, but cannot estimate the amount of reimbursement to be received at this time. Should necessary expenditures exceed our insurance coverage for damages incurred as a result of Hurricanes Ike and Gustav, or claims are denied by our insurance carrier for other reasons, we expect that our available cash on hand, cash flow from operations and the availability under our revolving loan facility will be sufficient to meet these future cash needs.

For a summary of hurricane remediation costs and credits for claims approved under our insurance policies that were included in lease operating expenses during the years ended December 31, 2010, 2009 and 2008, refer to Item 8 Financial Statements – *Note 3 – Hurricane Remediation and Insurance Claims*.

Following Hurricane Ike in 2008, insurance premiums increased dramatically and available coverage decreased with the renewal of our property policy effective June 1, 2009. However, the Gulf of Mexico experienced very little hurricane activity in 2009 and 2010 and we saw insurance premiums decrease and coverage improve slightly with the policy renewal effective June 1, 2010. Insurance premiums decreased from $35.2 million to $20.7 million over this time frame. We currently carry three layers of insurance coverage for our operating activities in the Gulf of Mexico. In June 2010, we renewed our insurance policies covering well control and hurricane damage. The current policy limits for well control and hurricane damage are $100 million and $85 million, respectively. We carry an additional $100 million of well control coverage on six wells at our Ship Shoal 349 field and six wells at our Matterhorn field. A retention amount of $5 million for well control events and $35 million per named windstorm occurrence must be satisfied by us before we are indemnified for losses. Certain properties we have deemed as non-core are not covered for hurricane damage; however, properties representing approximately 80% of our PV-10 value at December 31, 2010 are covered under our new insurance policies for hurricane damage. The properties purchased from Shell comprise approximately 11% of our PV-10 and are not currently covered for named windstorm damage. Since we closed on the Shell properties near the end of named windstorm season (June 1 to November 30) and our renewal is before the next named windstorm season, we elected not to purchase named windstorm insurance on the Shell assets for this interim period as we considered the probability as of a named windstorm remote. Pollution causing a negative environmental impact is characterized as a covered component of each of the well control and hurricane sections of the policy.

In May 2010, we renewed our general and excess liability policy, which provides for $250 million of liability coverage for bodily injury and property damage, including liability claims resulting from seepage, pollution or contamination. In May 2010, we renewed our insurance policy with respect to the Oil Spill Financial

Responsibility ("OSFR") requirement under the OPA, under which we are currently required to evidence $70 million of financial responsibility to the BOEMRE. We qualify to self-insure for $35 million of this amount, and the remaining $35 million is covered by our insurance policy. We may only collect proceeds under this OSFR policy after our well control, hurricane damage and excess liability policies have been exhausted.

In light of recent events in the Gulf of Mexico, 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. We are also exposed to the possibility that in the future 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. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

Capital expenditures. The level of our investment in oil and natural 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. The following table presents our capital expenditures for acquisitions, exploration, development and other leasehold costs:

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Acquisition of Total properties	$115,012	$ —	$ —
Acquisition of Shell properties	121,933	—	—
Acquisition of Apache property	—	—	116,551
Exploration (1)	60,164	90,636	337,587
Development (1)	77,230	162,111	265,295
Seismic, capitalized interest, other leasehold costs	41,314	23,387	55,446
Acquisitions and investments in oil and gas property/equipment	$415,653	$276,134	$774,879

(1) Reported by geography in the subsequent table.

The following table presents our exploration and development capital expenditures by geography:

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Conventional shelf	$115,503	$200,699	$472,514
Deepwater	9,358	45,911	81,593
Deep shelf	3,382	4,573	48,775
Onshore	9,151	1,564	—
Exploration and development capital expenditures	$137,394	$252,747	$602,882

Our 2010 capital expenditures, including acquisitions and investments, were financed by cash flow from operating activities and cash on hand.

During 2010, we participated in the drilling of six offshore and two onshore wells. The two onshore wells, which were both high risk/high potential exploration wells, were unsuccessful but five of the six offshore wells were successful. Of the five successful wells, four were exploration wells and one was a development well. All five of the successful wells were on the conventional shelf. We operate three of the five successful wells. As of December 31, 2010, we were in the process of drilling two onshore exploration wells in Texas and one offshore exploration well on the conventional shelf.

During 2009, we participated in the drilling of 10 gross exploratory wells and three gross development wells, of which 12 were on the conventional shelf and one was on the deep shelf. Two of the development wells were successful and eight of the exploratory wells were successful. We operate five of the eight successful exploratory wells.

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.

In 2010, we participated in bidding for Gulf of Mexico leases on the OCS at the March 2010 OCS Lease Sale conducted by the U.S. government through the BOEMRE. The BOEMRE awarded us five leases covering five OCS blocks located on the conventional shelf in the central Gulf of Mexico for a total lease bonus of approximately $8.7 million. Leases acquired from the BOEMRE in 2009 totaled three leases for a price of $0.7 million and in 2008 we acquired five leases for approximately $5.8 million.

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 are expected to yield less than our desired return on equity when abandonment costs are considered. In 2010, there were no significant property sales. In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our ARO by $128.5 million and we received proceeds of $32.2 million.

Our total capital expenditure budget for 2011 is $310 million which excludes acquisitions. The budget includes $161 million of capital to drill and evaluate 14 wells including 10 exploration and four development wells. The 14 wells are comprised of five on the conventional shelf, one in the deepwater, two on the deep shelf of the Gulf of Mexico and six wells located onshore. The budget also includes amounts for well completions, facilities capital, recompletions, seismic and leasehold items. Our 2011 capital budget is subject to change as conditions warrant and our budget is sufficiently flexible such that most any change can be made without penalty.

We intend to continue to pursue acquisitions and joint venture opportunities during 2011 should attractive opportunities arise. As described in the *Overview* section of this Item 7, we have entered into a letter of intent with Shell to acquire its working interest in a property along with certain related assets. The letter of intent provides for a purchase price of $55.0 million and we estimate the ARO attributable to our interest to be approximately $12.9 million. The purchase price will be adjusted for an effective date of September 1, 2010 and other normal closing adjustments. We are actively evaluating several other opportunities and expect to complement our drilling and exploitation projects with acquisitions providing acceptable rates of return. We anticipate funding our 2011 capital budget and acquisitions with internally generated cash flow, cash on hand and borrowings under our revolving loan facility.

Dividends. In 2010, we paid $59.6 million of dividends, which includes a special dividend of $49.2 million and regular dividends of $10.4 million. In 2009, we paid $9.2 million of regular dividends. In 2008, we paid dividends of $60.0 million, which includes a special dividend declared and paid in 2008 of $20.8 million, regular dividends declared and paid in 2008 of $6.9 million, a special dividend declared in 2007 and paid in 2008 of $30.0 million, and a regular dividend declared in 2007 and paid in 2008 of $2.3 million. Future special dividends cannot be predicted and are subject to approval of the board of directors, which will consider the performance of the Company, its financial condition, inputs from shareholders, future investment opportunities and other factors as the board of directors deems appropriate.

Capital Markets and Impact on Liquidity. During 2010, financial markets were robust and record amounts of debt and equity financing were completed by many in our industry. For 2011 to date, treasury yields have increased due to worries about federal policies and economic turmoil in Greece, Ireland, Spain and other countries. However, more recently, credit spreads have tightened and, as such, issuers are again actively pursuing both new issues and refinancings. We did not access the capital markets in 2010 as we were able to fund capital expenditures and acquisitions with internally generated cash flow, cash on hand and utilized borrowings under our revolving loan facility for short-term funding needs.

In 2009, the global financial markets and economic conditions were severely distressed. There were concerns of bank failures and liquidity concerns whether our banks would be able to meet their commitments under credit arrangements in place during that time. This caused limited financing transactions to be completed. In addition, prices for oil and natural gas had decreased from 2008.

Credit Agreement and long-term debt. The Credit Agreement, as amended, matures on July 23, 2012 and is a secured facility that is collateralized by a substantial portion of our oil and natural gas properties. Availability under the Credit Agreement 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. In November 2010, our borrowing base of $405.5 million was reaffirmed by our lenders. Any determination by our lenders to reduce our borrowing base will cause a similar reduction in the availability under our revolving loan facility. While we believe we will be able to obtain credit, there can be no assurance that we would be able to access the capital market on terms and conditions that would be acceptable to us, if the need were to arise.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends and share repurchases of up to $60.0 million per year, borrowings other than from the facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Letters of credit may be issued up to $90.0 million, provided availability under the revolving loan facility exists. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio; as such ratios are defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2010.

Borrowings under the revolving loan facility bear interest at either (1) the highest of the Prime Rate, the Federal Funds Rate plus 0.50%, or the one-month Eurodollar Rate plus 1.0%, plus a margin which varies from 0.75% to 1.75% 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 2.0% to 3.0% depending on the level of total borrowings under the Credit Agreement. The Credit Agreement also bears an unused commitment fee of 0.50%. The estimated effective interest rate on the revolving loan facility, including unused commitment fees and amortization of deferred financing costs, was 5.2% during the year ended December 31, 2010.

The Senior Notes bear an interest rate of 8.25%, payable semi-annually in arrears on June 15 and December 15. The estimated effective interest rate is 8.4% which incorporates the amortization of deferred financing costs. The Senior Notes are due June 2014 with no principal payments to be made until the due date.

As of December 31, 2010 and 2009, there were no borrowings outstanding under our revolving loan facility and $450.0 million of our Senior Notes outstanding. During each of the first three quarters of 2010, we borrowed $142.5 million under our revolving loan facility and repaid such borrowings during the quarter. In November, we borrowed $200.0 million under the revolving loan facility and repaid such borrowing during December 2010. As of December 31, 2010, we had $405.1 million of undrawn capacity under our revolving loan facility and had $0.4 million of letters of credit outstanding. The Senior Notes are classified as long-term.

For additional details about our long-term debt, refer to Item 8 *Financial Statements – Note 7 – Long-Term Debt*.

Asset retirement obligations. Each year (or more often if conditions warrant) we review, and to the extent necessary, revise our ARO estimates. ARO at December 31, 2010 were $391.3 million and were $348.8 million at December 31, 2009. See Item 8 *Financial Statements – Note 5 – Asset Retirement Obligations* for additional information regarding our estimation of our ARO.

Contractual obligations. The following summarizes our significant contractual obligations by maturity as of December 31, 2010. At December 31, 2010, we had no capital leases or long-term contracts for drilling rigs or equipment.

	Payments Due by Period at December 31, 2010				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years
	(Dollars in millions)				
Long-term debt – principal	$450.0	$ —	$ —	$450.0	$ —
Long-term debt – interest (1)	130.0	37.1	74.3	18.6	—
Drilling rigs	3.5	3.5	—	—	—
Operating leases	2.3	1.9	0.4	—	—
Asset retirement obligations	391.3	92.6	87.2	96.2	115.3
Derivatives	14.9	9.5	5.4	—	—
Other liabilities	2.4	—	2.4	—	—
	$994.4	$144.6	$169.7	$564.8	$115.3

(1) Interest on our Senior Notes, which bear interest at a fixed rate of 8.25%. Interest was calculated through the stated maturity date of the related debt.

Inflation and Seasonality

Inflation. For 2010, our realized prices for oil and natural gas increased 28.7% and 14.6%, respectively, from 2009. These are discussed in the *Overview* section above. Costs measured on a $/Mcfe basis decreased by 3.6% in 2010 compared to 2009. The cost per Mcfe is impacted by factors other than cost changes, such as insurance reimbursements and production levels. Historically, costs for goods and services have moved directionally with the price of oil and natural gas, as these commodities affect the demand for these goods and services. In the last two years, other factors have influenced the cost of goods and services. For example, in 2009, some offshore third-party contractors were in high demand associated with remediation work related to Hurricane Ike which increased the price for these types of contractors. In 2010, prices for offshore third-party contractors were relatively stable as drilling activity was curtailed due to the moratorium, but boat prices and other services escalated due to contract work for BP in connection with the clean up effort from the oil spill at the Macondo well. Other costs, such as insurance premiums, have decreased due to decreased hurricane activity. More recently, many commodity prices, including oil, copper, steel and other types of metals, have risen sharply. A portion of this increase is attributable to the economic recovery occurring in various parts of the world, as well as the weak US dollar and the prospect of inflation in the future as a result of record federal deficits.

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. 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 GAAP in the United States. The preparation of our financial statements requires us to make informed judgments 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 estimates on historical experience and other sources that we believe to be reasonable at the time. Changes in the facts and circumstances or the discovery of new information may result in revised estimates and actual results may vary from our estimates. Our significant accounting policies are detailed in Item 8 *Financial Statements – Note 1 – Significant Accounting Policies*. 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 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.

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 expenses related to these activities is permitted.

We amortize our investment in oil and natural gas properties, capitalized ARO and future development costs (including ARO of wells to be drilled) through DD&A, using the units-of-production method. The units-of-production method uses reserve information in its calculations. Estimating reserves requires significant judgments and is subject to change at each assessment. 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. We capitalize interest on unproved properties that are excluded from the amortization base. The costs of drilling non-commercial exploratory wells are included in the amortization base immediately upon determination that such wells are non-commercial.

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 costs, 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 costs 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 natural gas properties. Any write downs occurring as a result of a ceiling test impairment are not recoverable or reversible in future periods. We did not have a ceiling test impairment in 2010, but we did have ceiling test impairments in both 2009 and 2008 as a result of the significant decline in both oil and natural gas prices. Declines in oil and natural gas prices after December 31, 2010 may require us to record additional ceiling test impairments in the future.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of DD&A and impairment assessment of our oil and natural gas properties. We make changes to DD&A rates and impairment calculations in the same period that changes to our reserve estimates are made. Our proved reserve information as of December 31, 2010 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. 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;
- 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.

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.

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 the removal obligations may be 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 the *Asset Retirement and Environmental Obligations* topic of the FASB Accounting Standards Codification (the "Codification"), we are required to record a separate liability for the discounted present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet.

Inherent in the present value calculation of our liability are numerous estimates and judgments, including the ultimate settlement amounts, inflation factors, changes to our credit-adjusted risk-free rate, timing of settlement and changes in the legal, regulatory, environmental and political environments. Revisions to these estimates impact the value of our abandonment liability and our oil and natural gas property balance.

Fair value measurements. We measure the fair value of our derivative financial instruments by applying the income approach, using inputs that are derived principally from observable market data.

Income taxes. We provide for income taxes in accordance with the *Income Taxes* topic of the Codification, which 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 recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense.

Share-based compensation. In accordance with the *Compensation – Stock Compensation* topic of the Codification, we 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 the grant.

New Accounting Policies and Pronouncements

In December 2010, the FASB issued certain amendments to the *Business Combinations* topic of the Codification. The amendments specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual period only. In addition, the supplemental pro forma disclosures were expanded related to pro forma adjustments. The amendments are effective for our fiscal year ended December 31, 2011 and early adoption is permitted. As the amendments clarify certain disclosures, we have elected to adopt the amendments for our fiscal year ended December 31, 2010. The amendments only change disclosure requirements and not accounting practices; therefore, the adoption of these amendments did not have any impact on our financial position, results of operations or cash flows.

Effective for our annual reporting period ended December 31, 2009, we adopted certain amendments to the *Extractive Activities – Oil and Gas* topic of the Codification that updated and aligned the FASB's reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the SEC in December 2008. Periods reported prior to 2009 were not adjusted retrospectively. The amendments revised prices used and revised the definition of proved undeveloped reserves along with other changes. These amendments impacted our financial position and the results of operations as they affected our determination of DD&A expense and the calculations used in determining impairment assessment under the ceiling test rules. The amendments did not have an impact on our cash flows.

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. We have utilized derivatives to reduce the risk of fluctuations in commodity prices and expect to use these instruments in the future. We do not enter into derivative contracts for speculative purposes. We are currently a party to commodity option contracts.

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 2010, our income before income taxes would have decreased by approximately 55% in 2010. If costs and expenses of operating our properties had increased by 10% in 2010, our income before income taxes would have decreased by 14% in 2010.

During 2010, we entered into commodity option contracts to manage our exposure to commodity price risk from sales of oil and natural gas during the years ended December 31, 2011 and 2012. We have elected not to designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of volatile oil and natural gas prices, they may also limit future income from favorable price movements. For additional details about our commodity derivatives, refer to Item 8 *Financial Statements – Note 6 – Derivative Financial Instruments.* As of December 31, 2010, our open commodity derivatives were as follows:

Zero Cost Collars – Oil

Effective Date	Termination Date	Notional Quantity (Bbls)	Weighted Average NYMEX Contract Price		Fair Value Liability (in thousands)
			Floor	Ceiling	
1/1/2011	3/31/2011	668,200	$75.00	$92.96	$ 1,937
4/1/2011	6/30/2011	618,700	75.00	92.80	3,595
7/1/2011	9/30/2011	231,900	75.00	93.02	1,543
10/1/2011	12/31/2011	392,100	75.00	95.58	2,383
1/1/2012	3/31/2012	364,000	75.00	97.88	1,858
4/1/2012	6/30/2012	364,000	75.00	97.88	1,843
7/1/2012	9/30/2012	124,000	75.00	97.88	618
10/1/2012	12/31/2012	251,000	75.00	98.99	1,105
		3,013,900	$75.00	$95.16	$14,882

Interest rate risk. As of December 31, 2010, we did not have any variable rate debt outstanding, but we did have variable rate debt outstanding at various times during 2010. In 2010, if interest rates would have been 100 basis points higher (an additional 1%); our interest expense would have been approximately $1.0 million higher. We did not have any derivatives related to interest rates as of December 31, 2010.

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, 2010 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, 2010 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. and subsidiaries' internal control over financial reporting as of December 31, 2010, 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. and subsidiaries' 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. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of W&T Offshore, Inc. and subsidiaries as of December 31, 2010 and 2009, 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, 2010 of W&T Offshore, Inc. and subsidiaries and our report dated March 4, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 4, 2011

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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and natural gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), W&T Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March [x], 2011, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 4, 2011

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

	December 31, 2010	December 31, 2009
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 28,655	$ 38,187
Receivables:		
Oil and natural gas sales	79,911	54,978
Joint interest and other	25,415	51,312
Insurance	1,014	30,543
Income taxes	—	85,457
Total receivables	106,340	222,290
Deferred income taxes	5,784	—
Prepaid expenses and other assets	23,426	28,777
Total current assets	164,205	289,254
Property and equipment – at cost:		
Oil and natural gas properties and equipment (full cost method, of which $65,419 at December 31, 2010 and $77,301 at December 31, 2009 were excluded from amortization)	5,225,582	4,732,696
Furniture, fixtures and other	15,841	15,080
Total property and equipment	5,241,423	4,747,776
Less accumulated depreciation, depletion and amortization	4,021,395	3,752,980
Net property and equipment	1,220,028	994,796
Restricted deposits for asset retirement obligations	30,636	30,614
Deferred income taxes	2,819	5,117
Other assets	6,406	7,052
Total assets	$1,424,094	$1,326,833
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 80,442	$ 115,683
Undistributed oil and natural gas proceeds	25,240	32,216
Asset retirement obligations	92,575	117,421
Accrued liabilities	25,827	13,509
Income taxes payable	17,552	—
Deferred income taxes	—	5,117
Total current liabilities	241,636	283,946
Long-term debt, less current maturities – net of discount	450,000	450,000
Asset retirement obligations, less current portion	298,741	231,379
Other liabilities	11,974	2,558
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.00001 par value, 2,000,000 shares authorized and 0 issued at December 31, 2010 and at December 31, 2009	—	—
Common stock, $0.00001 par value; 118,330,000 shares authorized; 77,343,520 issued and 74,474,347 outstanding at December 31, 2010; 77,579,968 issued and 74,710,795 outstanding at December 31, 2009	1	1
Additional paid-in capital	377,529	373,050
Retained earnings	68,380	10,066
Treasury stock, at cost	(24,167)	(24,167)
Total shareholders' equity	421,743	358,950
Total liabilities and shareholders' equity	$1,424,094	$1,326,833

See accompanying notes.

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

	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per share data)		
Revenues	$705,783	$ 610,996	$1,215,609
Operating costs and expenses:			
Lease operating expenses	169,670	203,922	229,747
Production taxes	1,194	1,544	8,827
Gathering and transportation	16,484	13,619	15,957
Depreciation, depletion and amortization	268,415	308,076	482,464
Asset retirement obligation accretion	25,685	34,461	39,312
Impairment of oil and natural gas properties	—	218,871	1,182,758
General and administrative expenses	53,290	42,990	47,225
Derivative loss	4,256	7,372	16,464
Total costs and expenses	538,994	830,855	2,022,754
Operating income (loss)	166,789	(219,859)	(807,145)
Interest expense:			
Incurred	43,101	46,749	54,001
Capitalized	(5,395)	(6,662)	(19,292)
Loss on extinguishment of debt	—	2,926	—
Interest income	710	842	13,372
Income (loss) before income tax expense (benefit)	129,793	(262,030)	(828,482)
Income tax expense (benefit)	11,901	(74,111)	(269,663)
Net income (loss)	$117,892	$(187,919)	$ (558,819)
Basic and diluted earnings (loss) per common share	$ 1.58	$ (2.51)	$ (7.36)
Weighted average common shares outstanding	73,685	74,852	75,917

See accompanying notes.

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

	Common Stock Outstanding		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
	Shares	Value			Shares	Value		
	(In thousands)							
Balances at December 31, 2007	76,175	$ 1	$365,667	$ 786,803	—	$ —	$(1,131)	$1,151,340
Cash dividends:								
Common stock – regular ($0.09 per share)	—	—	—	(6,871)	—	—	—	(6,871)
Common stock – special ($0.27 per share)	—	—	—	(20,839)	—	—	—	(20,839)
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)
Other comprehensive income, net of tax	—	—	—	—	—	—	488	488
Net loss	—	—	—	(558,819)	—	—	—	(558,819)
Balances at December 31, 2008	76,291	1	372,595	200,274	—	—	(643)	572,227
Cash dividends:								
Common stock ($0.12 per share)	—	—	(6,861)	(2,289)	—	—	—	(9,150)
Share-based compensation	—	—	6,380	—	—	—	—	6,380
Restricted stock issued, net of forfeitures	1,471	—	3,014	—	—	—	—	3,014
Shares surrendered for payroll taxes	(182)	—	(2,078)	—	—	—	—	(2,078)
Repurchase of common stock	(2,869)	—	—	—	2,869	(24,167)	—	(24,167)
Other comprehensive income, net of tax	—	—	—	—	—	—	643	643
Net loss	—	—	—	(187,919)	—	—	—	(187,919)
Balances at December 31, 2009	74,711	1	373,050	10,066	2,869	(24,167)	$ —	358,950
Cash dividends:								
Common stock regular ($0.14 per share)	—	—	—	(10,446)	—	—	—	(10,446)
Common stock special ($0.66 per share)	—	—	—	(49,132)	—	—	—	(49,132)
Share-based compensation	—	—	5,533	—	—	—	—	5,533
Restricted stock issued, net of forfeitures	(95)	—	1,357	—	—	—	—	1,357
Shares surrendered for payroll taxes	(142)	—	(2,411)	—	—	—	—	(2,411)
Net income	—	—	—	117,892	—	—	—	117,892
Balances at December 31, 2010	74,474	$ 1	$377,529	$ 68,380	2,869	$(24,167)	$ —	$ 421,743

See accompanying notes.

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

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Operating activities:			
Net income (loss)	$ 117,892	$(187,919)	$ (558,819)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	294,100	345,637	521,776
Impairment of oil and natural gas properties	—	218,871	1,182,758
Amortization of debt issuance costs and discount on indebtedness	1,338	1,838	2,749
Loss on extinguishment of debt	—	2,817	—
Share-based compensation	5,533	6,380	6,029
Derivative loss	4,256	7,372	16,464
Cash payments on derivative settlements	874	(6,679)	(29,965)
Deferred income taxes	(8,266)	(346)	(249,445)
Other	—	998	833
Changes in operating assets and liabilities:			
Oil and natural gas receivables	(24,933)	(18,509)	77,017
Joint interest and other receivables	25,897	31,866	(35,885)
Insurance receivables	54,873	23,235	—
Income taxes	104,067	(52,100)	(46,930)
Prepaid expenses and other assets	4,536	(749)	4,917
Asset retirement obligations	(87,166)	(99,069)	(61,213)
Accounts payable and accrued liabilities	(31,885)	(117,230)	52,210
Other liabilities	3,656	(147)	—
Net cash provided by operating activities	464,772	156,266	882,496
Investing activities:			
Acquisition of property interest	(236,944)	(2,421)	(116,551)
Investment in oil and natural gas properties and equipment	(178,709)	(273,713)	(658,328)
Proceeds from sales of oil and natural gas properties and equipment	1,420	32,226	—
Proceeds from insurance	—	6,916	5,828
Purchases of furniture, fixtures and other, net	(760)	(705)	(4,812)
Net cash used in investing activities	(414,993)	(237,697)	(773,863)
Financing activities:			
Borrowings of other long-term debt	627,500	205,441	—
Repayments of long-term debt	(627,500)	(410,941)	(3,000)
Dividends to shareholders	(59,609)	(9,158)	(59,999)
Repurchases of common stock	—	(24,167)	—
Debt issuance costs	—	—	(2,000)
Other	298	891	(132)
Net cash used in financing activities	(59,311)	(237,934)	(65,131)
Increase (decrease) in cash and cash equivalents	(9,532)	(319,365)	43,502
Cash and cash equivalents, beginning of period	38,187	357,552	314,050
Cash and cash equivalents, end of period	$ 28,655	$ 38,187	$ 357,552

See accompanying notes.

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 primarily in the Gulf of Mexico.

Basis of Presentation

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

Reclassifications

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets 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 natural 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 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, 2010 and 2009, $6.5 million and $6.5 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 and large financial institutions. Our production is sold utilizing month-to-month contracts that are based on bid 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,		
	2010	2009	2008
Customer			
Shell Trading (US) Co.	40%	34%	33%
ConocoPhillips	17%	**	**
J.P. Morgan Ventures Energy Corp.	**	15%	**
Chevron Corp.	**	13%	19%

** 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 natural gas production as replacement customers could be obtained in a relatively short period of time.

Properties and Equipment

We use the full-cost method of accounting for oil and natural gas properties and equipment. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and natural 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 natural 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 $5.4 million, $6.7 million, and $19.3 million of interest expense during the years ended December 31, 2010, 2009, and 2008, respectively.

Oil and natural 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 ("ARO"), 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 natural 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 natural 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 natural gas properties. If the net capitalized cost of oil and natural gas properties (including capitalized ARO), net of related deferred income taxes, exceeds the present value of estimated future net revenues from proved reserves discounted at 10%, plus the cost of unproved oil and natural gas properties not being amortized, plus the lower of cost or estimated fair value of unproved oil and natural gas properties included in the amortization base, net of related tax effects, 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 used in the ceiling test as of December 31, 2010 and 2009 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for that year and exclude future cash outflows related to capitalized ARO and include future development costs and ARO related to wells to be drilled. For the ceiling test as of December 31, 2008 and March 31, 2009, commodity prices were based on the end-of-the-period prices using guidance effective for that reporting period. 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 in 2008 of $1.2 billion. Additionally, we recorded a ceiling test impairment in 2009 of $218.9 million primarily as a result of a further decline in natural gas prices as of March 31, 2009. Declines in oil and natural gas prices after December 31, 2010 may require us to record additional ceiling test impairments in the future. We did not have a ceiling test impairment during the year ended December 31, 2010.

Furniture, fixtures and non-oil and natural 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.

Asset Retirement Obligations

Pursuant to the *Asset Retirement and Environmental Obligations* topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification (the "Codification"), we are required to record a separate liability for the discounted present value of our ARO, with an offsetting increase to the related oil and natural gas properties on our balance sheet. 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 the removal obligations may be 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. For additional information, refer to Note 5.

Oil and Natural Gas Reserve Information

In January 2010, the FASB issued certain amendments to the *Extractive Activities – Oil and Gas* topic of the Codification that updated and aligned the FASB's reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the Securities and Exchange Commission ("SEC") in December 2008. The FASB's amendments and the SEC's new requirements became effective for annual reporting periods ending on or after December 31, 2009. Collectively, the new rules permit the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of *proved reserves* which was changed to indicate, among other things, that commencing with year-end 2009 entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period commodity prices, when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test for impairment have been changed from end-of-period commodity prices to the 12-month average commodity prices. Also, because it is our policy to use end-of-period reserves in the determination of quarterly depletion, our depreciation, depletion, amortization and accretion expense for the fourth quarter of 2009 and each of the quarters of 2010 were calculated using proved reserves that were determined in accordance with the new rules. Additionally, entities must separately disclose information about reserve quantities and certain financial statement amounts for geographic areas that represent 15 percent or more of proved reserves, and equity-method investees should be included in determining whether an entity has significant oil and gas producing activities. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years. Refer to Note 21 for additional information about our proved reserves and the impact of the new reserve estimation and disclosure requirements.

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. Our derivative instruments currently consist of commodity option contracts. We do not enter into derivative instruments for speculative trading purposes.

We account for derivative contracts in accordance with the *Derivatives and Hedging* topic of the Codification, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative’s fair value are required to 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, 2010, 2009 and 2008, changes in the fair value of our derivative contracts were recognized currently in earnings.

Fair Value of Financial Instruments

We include fair value information in the notes to our 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.

Income Taxes

We use the liability method of accounting for income taxes in accordance with the *Income Taxes* topic of the Codification. 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. We recognize uncertain tax positions in our financial statements when it is more likely than not that we will sustain the benefit taken or expected to be taken. When applicable, we recognize interest and penalties related to uncertain tax positions in income tax expense.

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

In accordance with the *Compensation—Stock Compensation* topic of the Codification, compensation cost for share-based payments to employees and non-employee directors is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which the recipient is required to provide service in exchange for the award.

Earnings (Loss) Per Share

In accordance with the *Earnings Per Share* topic of the Codification, 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. For additional information, refer to Note 14.

Recent Accounting Developments

In addition to the amendments to the *Extractive Activities—Oil and Gas* topic of the Codification that were previously discussed, the following recent accounting developments are applicable to the Company.

In December 2010, the FASB issued certain amendments to the *Business Combinations* topic of the Codification. The amendments specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual period only. In addition, the supplemental pro forma disclosures were expanded related to pro forma adjustments. The amendments are effective for our fiscal year ended December 31, 2011 and early adoption is permitted. As the amendments clarify certain disclosures, we have elected to adopt the amendments for our fiscal year ended December 31, 2010. These amendments only change disclosure requirements and not accounting practices; therefore, the adoption of these amendments did not have any impact on our financial position, results of operations or cash flows.

Previously issued amendments to the *Business Combination* topic became effective January 1, 2009, that require the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their respective fair values at the acquisition date. These amendments require the acquirer to record the fair value of contingent consideration (if any) at the acquisition date. Acquisition-related costs incurred prior to an acquisition are required to be expensed rather than included in the purchase-price determination. Also included in the amendments are guidance for recognizing and measuring the goodwill acquired in a business combination and guidance for determining what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of a business combination. These amendments apply prospectively to business combinations occurring on or after January 1, 2009. The adoption of these amendments did not have a material impact on the Company’s financial statements.

In January 2010, the FASB issued certain amendments to the *Fair Value Measurements and Disclosures* topic of the Codification. These amendments added new requirements for fair value disclosures about transfers into and out of Levels 1 and 2 and separate disclosures about purchases, sales, issuances and settlements relating to Level 3 measurements. The amendments also clarified existing requirements regarding the level of disaggregation as well as inputs and valuation techniques used to measure fair value. The amendments were adopted in our first quarter ended March 31, 2010, except for the requirement to provide Level 3 activity on a gross basis, which will be effective for our first quarter ended March 31, 2011. The amendments change disclosure requirements and not accounting practices; therefore, the adoption of these amendments did not have, nor is it expected to have, any impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued certain amendments to the *Financial Instruments* topic of the Codification that require public companies to include disclosures about the fair value of their financial instruments in interim reporting periods, as well as the methods, significant assumptions and any changes in such methods and assumptions used to estimate the fair value of financial instruments. These amendments became effective for interim reporting periods ending after June 15, 2009. The adoption of these amendments to the Codification did not have a material impact on the Company's financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Consolidation* topic of the Codification that establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The adoption of these amendments to the Codification did not have a material impact on the Company's financial statements.

Effective January 1, 2009, the Company adopted certain amendments to the *Derivatives and Hedging* topic of the Codification that changed the disclosure requirements for derivative instruments and hedging activities. Refer to Note 6 for additional information about the adoption of these amendments to the Codification.

2. Acquisitions and Divestitures

Acquisitions

During the year 2010, we closed on two major acquisition transactions. On April 7, 2010, we entered into a Purchase and Sale Agreement ("PSA") with Total E&P USA ("Total") and on April 30, 2010, through our wholly-owned subsidiary, W&T Energy VI, LLC ("Energy VI"), we acquired all of Total's interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $150 million, subject to customary closing adjustments, with an effective date of January 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $6.3 million. The properties acquired from Total are producing interests with future development potential, and include a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823). The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $115.0 million. This acquisition was funded with cash on hand. In accordance with the PSA, Energy VI obtained unsecured surety bonds in favor of the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE" and formerly the Minerals Management Service) to secure the ARO with respect to these assets. The PSA provides for annual increases in the required security for the ARO. To help satisfy the annual increases, Energy VI has agreed to make periodic payments from production of the acquired properties to an escrow agent. As long as the required security amount then in effect is met, the payments will be promptly released to us by the escrow agent. As of December 31, 2010, we were in compliance with the required security amount.

The following table presents the purchase price allocation for the acquisition of the Total properties (in thousands):

Oil and natural gas properties and equipment	$ 121,301
Asset retirement obligations—non-current	(6,289)
Total cash paid	$ 115,012

On November 3, 2010, we entered into an Asset Purchase Agreement ("APA") with Shell Offshore Inc. ("Shell") and on November 4, 2010, through Energy VI, we acquired all of Shell's interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico for a purchase price of $138.0 million, subject to customary closing adjustments and preferential rights elections, with an effective date of September 1, 2010. In addition, we assumed the ARO for plugging and abandonment of the acquired interest estimated at $18.0 million. The properties acquired from Shell are producing interests with future development potential, and include a 70% working interest in the Tahoe field (Viosca Knoll 783), 100% working interest in the Southeast Tahoe field (Viosca Knoll 784) and a 6.25% of 8/8ths overriding royalty interest in the Droshky field (Green Canyon 244). The purchase price was adjusted for, among other things, net revenue and operating expenses from the effective date to the closing date, resulting in a net payment of $121.9 million. Such amount is still subject to have further adjustments upon final settlement. This acquisition was funded with cash on hand. In accordance with the APA, Energy VI obtained unsecured surety bonds to secure the ARO with respect to these assets.

The following table presents the purchase price allocation for the acquisition of the Shell properties (in thousands):

Oil and natural gas properties and equipment	$ 139,889
Asset retirement obligations—non-current	(17,956)
Total cash paid	$ 121,933

The fair value of both purchases was determined to be the amount of cash paid plus the estimated amount of ARO assumed. The amount of cash paid was determined through management's analysis and evaluation of data provided by the seller, independent third-parties and internal sources. ARO were computed using the same methodology, cost estimates, inflation rate and discount rate as used for our other properties. No amounts were assigned to goodwill.

Amounts included in our consolidated statement of income related to the properties purchased from Shell and Total were $97.2 million of revenue and $32.1 million of net income for the year 2010.

Pro Forma Information—Unaudited

The unaudited pro forma financial information was computed as if the Shell and Total acquisitions had been completed as of the beginning of the 2009. The pro forma financial information is not necessarily indicative of the results of operations had the purchases occurred as of the beginning of 2009. The following table presents a summary of our pro forma consolidated results of operations for the years ended December 31, 2010 and 2009 (in thousands, except per share amounts).

	(unaudited) Year Ended December 31,	
	2010	2009
Revenue	$818,230	$ 742,779
Net income (loss)	148,359	(175,581)
Basic and diluted earnings (loss) per common share	1.99	(2.35)

The major assumptions used in computing the pro forma amounts were:

- Revenue and operating expenses relating to the acquisitions prior to the purchase date were obtained from the seller's records.
- Depreciation, depletion, and amortization were estimated using the full-cost method for capitalization and the units-of-production method. Reserve estimates determined at the respective purchase dates were used in the computations as if these reserves were purchased on January 1, 2009.

- No additional adjustments were made for impairment due to ceiling test evaluations.
- Accretion expense related to ARO was estimated using costs, inflation rate, discount rate and useful lives assumptions used in determining the liability as of December 31, 2010.
- One-time expense items related to acquiring the properties that were incurred in 2010 were reclassified to 2009.
- Reductions in interest income were computed related to cash paid for the acquisitions as cash on hand was sufficient to fund the acquisitions as of January 1, 2009. Average interest rates earned on short-term investments for the respective years were used in determining the adjustment.
- An incremental income tax rate of 35% was used in the calculations for the estimated incremental earnings before taxes.

Divestitures

In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. In connection with these transactions, we reduced our ARO by approximately $128.5 million and we received proceeds of approximately $32.2 million.

3. Hurricane Remediation and Insurance Claims

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 currently have insurance coverage for named windstorms but we do not carry business interruption insurance. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention of $10 million per occurrence that must be satisfied by us before we are indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) 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.

Below is a summary of remediation costs and amounts approved for payments related to Hurricanes Ike and Gustav that were included in lease operating expenses during the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Incurred	$ (1,380)	$ 37,062	$19,764
Less amounts approved for payment by insurers	(10,350)	(18,683)	(2,040)
Included in lease operating expenses	$(11,730)	$ 18,379	$17,724

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters' adjuster. Most all claims that have been processed in this manner have been paid on a timely basis. In 2010, incurred expenses were a credit due to revisions of previous estimates. See Note 5 for additional information about the impact of Hurricane Ike on our ARO.

Below is a reconciliation of our insurance receivables from December 31, 2009 to December 31, 2010 (in thousands):

Balance, December 31, 2009	$ 30,543
Costs approved under our insurance policies:	
Remediation	10,350
Plugging and abandonment	25,611
Payments received:	
Remediation	(11,597)
Plugging and abandonment	(53,893)
Balance, December 31, 2010	$ 1,014

From the third quarter of 2008 through December 31, 2010, we have received $120.2 million from our insurance carrier related to Hurricane Ike. At December 31, 2010, $0.1 million of remediation costs and $0.9 million related to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike are included in insurance receivables. At December 31, 2009, $1.3 million of remediation costs and $29.2 million of plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike are included in insurance receivables. We expect that our available cash and cash equivalents, cash flow from operations and the availability under our credit facility will be sufficient to meet any necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricanes Ike and Gustav.

4. Restricted Deposits

Restricted deposits as of December 31, 2010 and 2009 consisted of funds escrowed for the future plugging and abandonment of certain oil and natural gas properties. We are not obligated to contribute additional amounts to these escrowed accounts, except for the arrangement with Total as described in Note 2.

5. Asset Retirement Obligations

Pursuant to the *Asset Retirement and Environmental Obligations* topic of the Codification, an asset retirement obligation associated with the retirement of a tangible long-lived asset is required to 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 fair value of the ARO is measured using expected cash outflows associated with the ARO, discounted at our credit-adjusted risk-free rate when the liability is initially recorded. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

The following is a reconciliation of our ARO liability as of December 31, 2010 and 2009 (in thousands).

	2010	2009
Asset retirement obligation, beginning of period	$348,800	$ 547,897
Liabilities settled	(87,166)	(99,069)
Accretion of discount	25,685	34,461
Disposition of properties	(2,070)	(128,467)
Liabilities assumed through acquisition	24,477	12,816
Liabilities incurred	503	343
Revisions of estimated liabilities due to Hurricane Ike	41,952	77,271
Revisions of estimated liabilities due to NTL 2010-G05 (1)	18,725	—
Revisions of estimated liabilities—all other	20,410	(96,452)
Asset retirement obligation, end of period	391,316	348,800
Less current portion	92,575	117,421
Long-term	$298,741	$ 231,379

(1) NTL No. 2010-G05, *"Decommissioning Guidance for Wells and Platforms"* issued by the BOEMRE on September 15, 2010 and effective as of October 15, 2010, will require us to decommission any wells and platforms that have not been used during the past five years for exploration or production on active leases and are no longer capable of producing in paying quantities within three years. The accelerated time frame will cause our estimated liabilities for ARO to be incurred in earlier periods, resulting in a higher present value of such liabilities.

Each year (or more often if conditions warrant) we review and, to the extent necessary, revise our ARO estimates. During 2010, we reduced our ARO by $87.2 million for work performed to settle our liabilities (including $62.9 million to plug and abandon wells and facilities damaged by Hurricane Ike). Offsetting this decrease were the acquisitions of properties, including the properties from Total and Shell, which increased our obligations by $24.5 million. In addition, revisions were made related to Hurricane Ike which increased the liability by $42.0 million and there was an $18.7 million increase related to a change in regulation which accelerated the decommissioning of wells and platforms. Other estimates were increased by $20.4 million primarily due to an increase in the scope of work and time required to complete the work for non-operated and operated properties and changes to estimates in useful lives.

In 2009, we reduced our ARO by $99.1 million for work performed to settle our liabilities (including $51.9 million to plug and abandon wells and facilities damaged by Hurricane Ike) and by $128.5 million for asset dispositions. In addition, we decreased our estimates of future ARO by $96.5 million, a portion of which relates to useful life extensions while the remainder primarily relates to recent cost reductions we experienced in the marketplace for decommissioning, site clearance and removal of certain of our operated structures and pipelines. Conversely, our estimated ARO increased by $12.8 million related to additional interests we acquired in certain fields during the fourth quarter of 2009 and by $77.3 million, the majority of which relates to revised estimates for the dismantlement of two operated platforms that were toppled during Hurricane Ike and the plugging and abandonment of the associated wells. The remainder of the increase relates to revised estimates related to other wells and facilities damaged by such storm. See Note 3 for additional details about the impact of Hurricane Ike on our financial statements.

6. Derivative Financial Instruments

We account for derivative contracts in accordance with the *Derivatives and Hedging* Topic of the Codification, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative's fair value are required to be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is entered into.

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, 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 revolving loan facility. We do not enter into derivative instruments for speculative trading purposes. Our derivative instruments currently consist of commodity option contracts. The Company is exposed to credit loss in the event of nonperformance by the counterparties; however, none is currently anticipated.

We measure the fair value of our derivatives by applying the income approach, using inputs that are classified within Level 2 of the valuation hierarchy.

Commodity Derivatives

During 2010, we entered into commodity option contracts to manage our exposure to commodity price risk from sales of oil for the years ended December 31, 2011 and 2012. We have elected not to designate our commodity derivatives as hedging instruments. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. As of December 31, 2010, our open commodity derivatives were as follows:

Zero Cost Collars – Oil

Effective Date	Termination Date	Notional Quantity (Bbls)	Weighted Average NYMEX Contract Price		Fair Value Liability (in thousands)
			Floor	Ceiling	
1/1/2011	3/31/2011	668,200	$75.00	$92.96	$ 1,937
4/1/2011	6/30/2011	618,700	75.00	92.80	3,595
7/1/2011	9/30/2011	231,900	75.00	93.02	1,543
10/1/2011	12/31/2011	392,100	75.00	95.58	2,383
1/1/2012	3/31/2012	364,000	75.00	97.88	1,858
4/1/2012	6/30/2012	364,000	75.00	97.88	1,843
7/1/2012	9/30/2012	124,000	75.00	97.88	618
10/1/2012	12/31/2012	251,000	75.00	98.99	1,105
		3,013,900	$75.00	$95.16	$14,882

At December 31, 2010, $9.5 million was included in accrued liabilities and $5.4 million was included in other long-term liabilities related to our commodity derivative contracts. Changes in the fair value of our commodity derivative contracts are recognized currently in earnings. Our derivative loss for the year ended December 31, 2010 includes a realized gain of $5.5 million and an unrealized loss of $9.5 million, related to our commodity derivatives. Our derivative loss for the year ended December 31, 2009 includes realized and unrealized losses of $0.2 million and $5.4 million, respectively, related to our commodity derivatives. Our derivative loss for the year ended December 31, 2008 includes a realized loss of $27.4 million and an unrealized gain of $17.4 million related to our commodity derivatives.

Interest Rate Swap

Our interest rate swap contract with a fixed interest rate of 5.21% expired in August 2010. Initially, this swap was designated as a hedge of the floating-rate interest payments on our previously outstanding term loan facility ("Tranche B"). However, as a result of payments on the term loan and changes to the swap contract, hedge accounting was discontinued completely in 2007. Changes in fair value subsequent to the discontinuation of hedge accounting were immediately recognized in earnings.

For the years ended December 31, 2010, 2009 and 2008, we recorded losses of $0.3 million, $1.8 million and $6.5 million, respectively.

7. Long-Term Debt

As of December 31, 2010 and 2009 our long-term debt was as follows (in thousands):

	December 31,	
	2010	2009
8.25% Senior Notes, due June 2014	$450,000	$450,000
Total long-term debt	450,000	450,000
Current maturities of long-term debt	—	—
Long-term debt, less current maturities	$450,000	$450,000

Aggregate annual maturities of long-term debt as of December 31, 2010 are as follows (in millions): 2011–$0.0; 2012–$0.0; 2013–$0.0; 2014–$450.0; thereafter–$0.0.

During 2009, we repaid the Tranche B term loan facility in full with borrowings under our revolving loan facility. As a result, in 2009 we recorded a loss of $2.9 million related to the write-off of deferred financing costs and other related incidental costs.

See Note 8 for the estimated fair value of our Senior Notes.

8.25% Senior Notes due 2014

The Senior 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%, which incorporates amortization of deferred issuance costs.

The Company and its restricted subsidiaries are subject to certain covenants under the indenture governing the Senior 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, as amended, matures on July 23, 2012 and is a secured facility that is collateralized by our oil and natural gas properties. Availability under the Credit Agreement 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. In November 2010, our borrowing base of $405.5 million was reaffirmed by our lenders. Any determination by our lenders to reduce our borrowing base will cause a similar reduction in the availability under our revolving loan facility.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends and share repurchases of up to $60.0 million per year, borrowings other than from the facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Letters of credit may be issued up to $90.0 million, provided availability under the revolving loan facility exists. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio as such ratios are defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of December 31, 2010.

Borrowings under the revolving loan facility bear interest at either (1) the highest of the Prime Rate, the Federal Funds Rate plus 0.50%, or the one-month Eurodollar Rate plus 1.0%, plus a margin which varies from 0.75% to 1.75% 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 2.0% to 3.0% depending on the level of total borrowings under the Credit Agreement. The Credit Agreement also bears an unused commitment fee of 0.50%. The estimated effective interest rate on the revolving loan facility, including unused commitment fees and amortization of deferred financing costs, was 5.2% and 4.8% for the years ended December 31, 2010 and 2009, respectively.

As of December 31, 2010 and 2009, there were no borrowings outstanding under our revolving loan facility. During each of the first three quarters of 2010, we borrowed $142.5 million under our revolving loan facility and repaid such borrowings during the quarter. In November, we borrowed $200.0 million and repaid such borrowing during December 2010. As of December 31, 2010, we had $405.1 million of undrawn capacity under our revolving loan facility and $0.4 million of letters of credit outstanding under our revolving loan facility.

8. Fair Value Measurements

Under the *Fair Value Measurements and Disclosures* topic of the Codification, 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.

The following table presents the fair value of our derivatives financial instruments and our long-term Senior Notes (in thousands).

		December 31,			
		2010		2009	
	Hierarchy	Assets	Liabilities	Assets	Liabilities
Derivatives	Level 2	$ —	$ 14,882	$100	$ 9,852
Senior Notes	Level 2	—	441,000	—	432,000

Derivatives are reported in the statement of financial position at fair value. The Senior Notes are reported in the statement of financial position at their carrying value of $450.0 million at December 31, 2010 and 2009.

We measure the fair value of our derivative financial instruments by applying the income approach, using inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for our derivative financial instruments fair value measurement are the exercise price, the expiration date, the settlement date, notional quantities, the averaging volatility start date, the discount curve with spreads, volatility and published commodity futures prices. The fair value of our Senior Notes is based on quoted prices and the market is not an active market, therefore the fair value is classified within Level 2. Previously, the fair value for the Senior Notes was classified as Level 1, but upon further assessment with our agent as to whether an active market existed for our Senior Notes, we noted that our Senior Notes are not traded frequently. Therefore, we decided the Level 2 classification was more appropriate for our Senior Notes. For additional details about our derivative financial instruments, refer to Note 6 and for additional information on Senior Notes refer to Note 7.

9. Equity Structure and Transactions

As of December 31, 2010 and 2009, 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 March 2009, we announced a $25 million stock repurchase program, which expired on December 31, 2009. In 2009, we purchased 2,869,173 shares of our common stock for approximately $24.2 million in the open market in accordance with the repurchase program. Repurchases were funded with cash on hand.

During the years ended December 31, 2010, 2009 and 2008, we paid regular cash dividends of $0.14, $0.12 and $0.12 per common share per year, respectively. In December, 2010, we paid a special dividend of $0.66 per share or $49.2 million. In January 2008, we paid a special cash dividend of $0.39 per common share, or $30.0 million and in December 2008, we paid a special cash dividend of $0.27 per common share, or $20.8 million. On March 1, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on March 31, 2011 to shareholders of record on March 15, 2011.

10. Incentive Compensation Plan

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, (the “Plan”) was approved by the Company’s shareholders and covers the Company’s eligible employees and consultants. The Plan is an amended and restated version of the Company’s previous Long-term Incentive Compensation Plan (the “Previous Plan”). In addition to other cash and equity-based compensation awards, the Plan is designed to grant awards that qualify as performance-based compensation within the meaning of section 162(m) of the Internal Revenue Code. The Plan grants the Compensation Committee of the Board of Directors administrative authority over all participants, and grants the President and Chief Executive Officer with authority over the administration of awards granted to participants that are not subject to section 16 of the Exchange Act (as applicable, the "Committee"). The administrative authority includes setting the terms and provisions of each award granted and modifications to previously granted awards with certain restrictions.

Pursuant to the terms of the Plan, the Committee establishes the performance criteria and may use a single measure or combination of business measures as described in the Plan. Also, individual goals are established by the Committee for certain individuals. Performance awards may be granted in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, or other awards related to stock, and awards may be paid in cash, stock, or any combination of cash and stock, as determined by the Committee. The performance awards granted under the Plan can be measured over a performance period up to ten years and annual incentive awards (a type of performance award) will be paid within 90 days following the applicable year end.

For 2010, performance awards under the Plan were granted in the form of restricted stock units ("RSUs") and cash awards. As defined by the Plan, RSUs are rights to receive stock, cash or a combination thereof at the end of a specified vesting period, subject to certain terms and conditions as determined by the Committee. The sole business performance criteria established for the 2010 RSU awards was an earnings per share target. The Company exceeded the top-tier target; therefore 100% of the RSU awards will be eligible for vesting on December 15, 2012. The cash based awards were determined based on multiple performance measures, such as earnings per share and revenue growth, and individual performance measures as well. With respect to the 2010 cash basis awards, most of the performance criteria targets were achieved and employees will be paid their cash awards within 75 days following year end 2010.

The Previous Plan utilized by the Company consisted of a general award and an extraordinary performance award. In 2009, the Company's performance did not achieve any of the targets; therefore no awards were granted that were related to Company performance. For 2008, the bonus pool was computed to pay 100% of the general award to all eligible employees. As extraordinary performance goals were not met in 2008, no extraordinary performance award was awarded for 2008 pursuant to the incentive plan in effect for that year.

In 2009, the Compensation Committee approved a modification to the restricted stock portion of the 2008 award. Due to a decline in the market price of the Company's common stock, the Compensation Committee determined that the number of shares available for issuance under the Previous Plan was insufficient to cover 100% of the restricted stock portion of the 2008 award. Accordingly, in March 2009, the Company granted to its eligible employees, on a pro-rata basis, substantially all of the shares of restricted stock available to be issued under the Previous Plan, representing 1,124,603 restricted shares of our common stock with a fair value on the dates of grant of approximately $6.0 million. In May 2009, the Company's shareholders approved an increase in the number of shares available for issuance under the Previous Plan of 2,000,000 shares. Subsequent to the increase in the number of shares available, the Company granted to its employees 413,513 shares of restricted stock with a fair value on the date of grant of approximately $4.5 million to satisfy the remainder of the 2008 award.

For information concerning grants awarded and amounts recognized in lease operating expense and general and administrative expense, see Note 11.

11. Share-Based Compensation and Cash-Based Incentive Compensation

In accordance with the *Compensation – Stock Compensation* topic of the Codification, we 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. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that actually vest.

As allowed by the Plan, in August 2010, the Company granted RSUs to certain of its employees and can use RSUs in the future. Prior to 2010, the Company granted restricted stock to its employees. In 2010 and in prior years, restricted stock was granted to the Company's non-employee directors under the Director Compensation Plan. The Company currently intends to use restricted stock for its non-employee directors in the future. In addition to share-based compensation, the Company has in the past granted to its employees cash incentive awards.

At December 31, 2010, there were 2,131,823 shares of common stock available for award under the Plan and 583,891 shares of common stock available for award under the Directors Compensation Plan.

Restricted Stock: In 2008 and 2009, the Company issued to its employees restricted shares in connection with its share-based payment plans. In 2010, 2009 and 2008, restricted shares were issued to the Company's non-employee directors. Restricted shares are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted 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.

A summary of share activity related to restricted stock for the years ended December 31, 2010, 2009 and 2008 is as follows:

	2010		2009		2008	
	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	1,050,506	$ 8.48	233,703	$30.33	277,584	$29.17
Granted	35,000	10.00	1,570,436	6.91	204,139	32.41
Vested	(485,934)	9.69	(653,676)	12.18	(221,822)	30.80
Forfeited	(129,180)	8.15	(99,957)	10.77	(26,198)	30.30
Nonvested, end of period	470,392	7.42	1,050,506	8.48	233,703	30.33

At December 31, 2010, the composition of our restricted stock awards outstanding, by year granted, was as follows:

	Shares
Employees—granted in:	
2009	411,659(1)
Non-employee directors—granted in:	
2010	35,000(2)
2009	21,545(3)
2008	2,188(4)
Total	470,392

Vesting is expected to occur as follows, less any forfeitures:

(1) December 2011.
(2) Equal installments in May 2011, 2012 and 2013.
(3) Equal installments in May 2011 and 2012.
(4) May 2011.

The grant date fair value of restricted stock granted during the years ended December 31, 2010, 2009 and 2008 was $0.4 million, $10.9 million and $6.6 million, respectively, The fair value of the restricted stock that vested during the years ended December 30, 2010, 2009 and 2008 was $8.1 million, $7.4 million and $3.4 million, respectively, based on the closing prices on the dates of vesting.

Restricted Stock Units: During 2010, the Company awarded RSUs to certain employees that were 100% contingent upon meeting a specified performance requirement, an earnings per share target for the year 2010, which was achieved. Vesting occurs upon completion of the specified vesting period. RSUs earn dividends if and when the contingency is met at the same rate as our common stock. The contingency was met as of December 31, 2010. RSUs are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period.

A summary of share activity related to RSUs for the year ended December 31, 2010, is as follows:

	Restricted Stock Units	
	Units (1)	Weighted Average Grant Date Fair Value Per Unit
Outstanding RSUs, December 31, 2009	—	$ —
Granted	1,280,501	9.36
Vested	—	—
Forfeited	(13,884)	9.36
Outstanding RSUs, December 31, 2010	1,266,617	9.36

(1) All of the RSUs granted in 2010 will vest in December 2012 subject to continuous service conditions.

The weighted average grant date fair value of restricted stock units granted during the year ended December 31, 2010 was $12.0 million.

A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit for the years ended December 31, 2010, 2009 and 2008 is as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Share-based compensation expense from:			
Restricted stock	$3,469	$7,730	$8,078
Restricted stock units	2,064	—	—
Total	$5,533	$7,730	$8,078
Share-based compensation tax benefit:			
Tax benefit computed at the statutory rate	$1,937	$2,706	$2,827

As of December 31, 2010, unrecognized share-based compensation expense related to our issued restricted shares and RSUs was $2.4 million and $9.5 million, respectively. The unrecognized expense related to restricted shares was decreased by $0.8 million for the year ended December 31, 2010 due to a change in the estimated forfeiture rate based upon historical experience. Unrecognized compensation expense will be recognized through April 2013 for restricted shares and November 2012 for RSUs.

Cash-based Incentive Compensation: As defined by the Plan, annual incentive awards may be granted to eligible employees payable in cash. These awards are performance-based awards consisting of one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

Share-Based Compensation and Cash-Based Incentive Compensation Expense: A summary of incentive compensation expense for the years ended December 31, 2010, 2009, and 2008 is as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Share-based compensation expense included in:			
Lease operating expense	$ 748	$ 2,242	$ 1,192
General and administrative	4,785	5,488	6,886
Total charged to operating income (loss)	5,533	7,730	8,078
Cash-based incentive compensation included in:			
Lease operating expense	2,067	1,472	1,262
General and administrative	8,539	1,525	4,983
Total charged to operating income (loss)	10,606	2,997	6,245
Total incentive compensation charged to operating income (loss)	$16,139	$10,727	$14,323

12. 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 2010, 2009 and 2008, 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, $1.5 million and $1.4 million for the years ended December 31, 2010, 2009 and 2008, respectively.

13. Income Taxes

Income Tax Expense (Benefit)

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

	Year Ended December 31,		
	2010	2009	2008
Current federal	$20,135	$(74,038)	$ (20,356)
Current state	32	(73)	138
Deferred federal	(8,266)	—	(249,445)
	$11,901	$(74,111)	$(269,663)

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,					
	2010		2009		2008	
Income tax expense (benefit) at the federal statutory rate	$ 45,427	35.0%	$(91,710)	35.0%	$(289,969)	35.0%
Valuation allowance	(31,985)	(24.6)	14,594	(5.6)	17,391	(2.1)
Domestic production activities deduction	(2,623)	(2.0)	3,167	(1.2)	1,048	(0.2)
Share-based compensation	—	—	208	—	1,214	(0.2)
State income taxes	32	—	(73)	—	138	—
Other	1,050	0.8	(297)	0.1	515	—
	$ 11,901	9.2%	$(74,111)	28.3%	$(269,663)	32.5%

Our effective tax rate for the year ended December 31, 2010 primarily reflects a reduction in our valuation allowance against our deferred tax assets and the utilization of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code. Taxable income in 2010 allowed us to reverse all of the previously recorded valuation allowance. Our effective tax rate for the year ended December 31, 2009 primarily reflects recapture of the deduction attributable to qualified domestic production activities under Section 199 of the Internal Revenue Code related to net operating loss carrybacks for tax purposes as well as the incremental current period effect of a change in our valuation allowance for our deferred tax assets. Our effective tax rate for the year ended December 31, 2008 primarily reflects the effect of a valuation allowance for our deferred tax assets. In 2009 and 2008, 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. In 2009, a portion of the qualified domestic production activities deduction for 2005 and 2007 was recaptured due to carrybacks of a net operating loss from 2009 to 2005 and 2007. 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 from 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, 2010	December 31, 2009
Deferred tax liabilities:		
Property and equipment	$ 2,370	$ —
Other	3,274	5,641
Total deferred tax liabilities	5,644	5,641
Deferred tax assets:		
Minimum tax credit	3,558	23,576
Property and equipment	—	9,125
State net operating loss	4,176	3,483
Derivatives	4,622	2,827
Valuation allowance	(4,176)	(35,468)
Other	6,067	2,098
Total deferred tax assets	14,247	5,641
Net deferred tax assets	$ 8,603	$ —

During the year ended December 31, 2010, we received refunds of federal income taxes paid in prior years totaling $99.8 million, consisting primarily of carrybacks of net operating losses generated in 2009 and 2008. On November 6, 2009, the Worker, Homeownership and Business Assistance Act of 2009 was signed into law. A provision of this act provides an election to increase the carryback period for applicable net operating losses up to five years from two years.

During the year ended December 31, 2009, we recorded a ceiling test impairment of $218.9 million, which resulted in a deferred tax asset balance related to our oil and gas properties and equipment. Additionally, we recorded a minimum tax credit of $23.6 million resulting in a deferred tax asset which was fully offset by a valuation allowance. At December 31, 2009, we had a federal income tax receivable of $85.5 million. This amount is comprised principally of a net operating loss carryback from 2008 to 2007 of $8.9 million and a net operating loss carryback from 2009 to 2004, 2005, and 2007 of $22.1 million, $40.0 million and $14.1 million, respectively.

Net Operating Loss and Tax Credit Carryovers

The table below presents the details of our net operating loss and tax credit carryovers as of December 31, 2010 (in thousands):

	Amount	Expiration Year
State net operating loss	$80,316	2020-2025
Minimum tax credit	3,558	Indefinite

Valuation Allowance

As of December 31, 2010, we have a valuation allowance related to state net operating losses. The valuation allowance on our books as of December 31, 2009 related to federal income taxes was reversed in full during

2010. Taxable income in 2010 allowed us to reverse all of the previous recorded valuation allowance. Deferred tax assets are recorded on net operating losses, minimum tax credits and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. Minimum tax credits are attributable to net minimum tax paid in prior years as a result of net operating loss carrybacks from 2009 to prior years. 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 offset substantially all of our deferred tax assets at December 31, 2009.

Uncertain Tax Positions

The table below sets forth the reconciliation of the beginning and ending balances of the total amount of unrecognized tax benefits. There are no unrecognized benefits that would impact the effective tax rate if recognized. While amounts could change in the next 12 months, we do not anticipate it having a material impact on our financial statements. We recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2010, we had $0.3 million of accrued interest related to uncertain tax positions. During 2010, we recognized $0.2 million in income tax expense for interest and penalties.

Changes in the balance of unrecognized tax benefits excluding tax interest and penalties are as follows (in thousands):

Balance at December 31, 2009	$ —
Increases related to current-year tax positions	3,558
Balance at December 31, 2010	$3,558

The tax years from 2007 through 2010 remain open to examination by the tax jurisdictions to which we are subject.

14. Earnings (Loss) Per Share

In accordance with the *Earnings Per Share* topic of the Codification, the Company's unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are deemed participating securities and are included in the computation of earnings per share under the two-class method.

The following table presents the calculation of basic earnings (loss) per common share for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per share amounts):

	Year Ended December 31,		
	2010	2009	2008
Net income (loss)	$117,892	$(187,919)	$(558,819)
Less portion allocated to nonvested shares	1,178	—	—
Net income (loss) allocated to common shares	$116,714	$(187,919)	$(558,819)
Weighted average common shares outstanding	73,685	74,852	75,917
Basic and diluted earnings (loss) per common share	$ 1.58	$ (2.51)	$ (7.36)
Shares excluded due to being anti-dilutive	1,540	1,347	405

15. Comprehensive Income (Loss)

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

	Year Ended December 31,		
	2010	2009	2008
Net income (loss)	$117,892	$(187,919)	$(558,819)
Amounts reclassified to income, net of income tax of $0 in 2010, $346 in 2009 and $263 in 2008 (1)	—	643	488
Comprehensive income (loss)	$117,892	$(187,276)	$(558,331)

(1) Includes the amortization of amounts recorded in other comprehensive income upon the de-designation of our interest rate swap as a cash flow hedge in 2007. Refer to Note 6.

The balance in accumulated other comprehensive loss at December 31, 2008 was related entirely to our interest rate swap.

16. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2010	2009	2008
Cash paid for interest, net of interest capitalized of $5,395 in 2010, $6,662 in 2009 and $19,292 in 2008	$36,362	$37,286	$31,231
Cash paid for income taxes	12,000	100	26,591
Cash paid for share-based compensation (1)	452	162	161
Cash tax benefit related to share-based compensation (2)	6,871	—	—

(1) The cash paid for share-based compensation is for dividends on unvested restricted stock. No cash was received from employees or directors related to share-based compensation and no cash was used to settle any equity instruments granted under share-base compensation arrangements.

(2) The cash tax benefit for share-based compensation is attributable to tax deductions for vested restricted shares and dividends paid on unvested restricted stock. Tax refunds were received in 2010 that included carrybacks of net operating losses for the years 2009 and 2008 to prior years, therefore the tax cash benefits from share-based compensation in those years was determined to be received in 2010. In addition, refunds related to the carryback of 2008 net operating loss to prior years were also received in 2009. As refunds could not be specifically determined as to which related to share-based compensation, it was assumed these cash flows were received in 2010 as most refunds were received in that year.

During the years ended December 31, 2010 and December 31, 2009, we received refunds of federal income taxes paid in prior years totaling $99.8 million and $22.3 million, respectively.

17. Commitments

We have operating lease agreements for office space and office equipment, which terminate in August 2013. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2010 are as follows (in millions): 2011–$1.9; 2012–$0.3; 2013–$0.1; thereafter–$0.0.

Total rent expense was approximately $2.0 millions, $2.2 million, and $2.1 million during the years ended December 31, 2010, 2009 and 2008, respectively.

18. Contingencies

In the third quarter of 2009, the Company recognized $5.3 million in allowable reductions of cash payments for royalties owed to the BOEMRE for transportation of their deepwater production through our subsea pipeline systems. In 2010, BOEMRE audited the calculations and support related to this usage fee, and in the third quarter, we were notified that BOEMRE had disallowed approximately $4.7 million of the reductions taken. We recorded a reduction to other revenue of $4.7 million in the third quarter of 2010 to reflect this disallowance; however, we disagree with the position taken by BOEMRE and plan to pursue our claim, including taking legal action, if necessary, to resolve the matter.

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. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business. Although we can give no assurance about the outcome of pending legal and federal or state 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.

19. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2010 and 2009 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2010				
Revenues	$ 169,585	$179,667	$169,575	$186,956
Operating income	55,711	40,178	36,847	34,053
Net income	42,315	27,870	27,188	20,519
Basic/diluted earnings per common share (1)	0.57	0.37	0.36	0.27
Year Ended December 31, 2009 (2)				
Revenues	$ 117,422	$150,432	$167,042	$176,100
Operating income (loss)	(258,347)	(3,769)	7,322	34,935
Net income (loss)	(244,577)	(5,974)	(1,322)	63,954
Basic/diluted earnings (loss) per common share (1)	(3.22)	(0.08)	(0.02)	0.84

(1) 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.

(2) The carrying amount of our oil and natural gas properties was written down by $218.9 million as of March 31, 2009 through application of the full cost ceiling limitation as prescribed by the SEC, primarily as a result of lower natural gas prices at March 31, 2009.

20. Supplemental Guarantor Information

Our payment obligations under the Notes and the Credit Agreement (see Note 7) are fully and unconditionally guaranteed by our wholly-owned subsidiary, Energy VI ("Guarantor Subsidiary"). The guaranty of the Credit Agreement became effective on April 30, 2010.

The following unaudited condensed consolidating financial information presents the financial condition, results of operations and cash flows of W&T Offshore, Inc. and Energy VI, together with consolidating adjustments necessary to present the Company's results on a consolidated basis.

Condensed Consolidating Balance Sheet as of December 31, 2010

	Parent Company	Guarantor Subsidiary (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$ 28,655	$ —	$ —	$ 28,655
Receivables:				
Oil and natural gas sales	50,421	29,490	—	79,911
Joint interest and other	25,415	—	—	25,415
Insurance	1,014	—	—	1,014
Income taxes	2,492	—	(2,492)	—
Total receivables	79,342	29,490	(2,492)	106,340
Deferred income taxes	5,784	2,755	(2,755)	5,784
Prepaid expenses and other assets	23,426	—	—	23,426
Total current assets	137,207	32,245	(5,247)	164,205
Property and equipment—at cost:				
Oil and natural gas properties and equipment	4,955,460	270,122	—	5,225,582
Furniture, fixtures and other	15,841	—	—	15,841
Total property and equipment	4,971,301	270,122	—	5,241,423
Less accumulated depreciation, depletion and amortization	3,994,085	27,310	—	4,021,395
Net property and equipment	977,216	242,812	—	1,220,028
Restricted deposits for asset retirement obligations	30,636	—	—	30,636
Deferred income taxes	2,819	—	—	2,819
Other assets	275,461	47,160	(316,215)	6,406
Total assets	$1,423,339	$322,217	$(321,462)	$1,424,094
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable	$ 77,422	$ 3,020	$ —	$ 80,442
Undistributed oil and natural gas proceeds	24,866	374	—	25,240
Asset retirement obligations	92,575	—	—	92,575
Accrued liabilities	25,827	—	—	25,827
Income taxes	—	20,044	(2,492)	17,552
Total current liabilities	220,690	23,438	(2,492)	241,636
Long-term debt	450,000	—	—	450,000
Asset retirement obligations, less current portion	269,016	29,725	—	298,741
Deferred income taxes	2,755	—	(2,755)	—
Other liabilities	59,135	—	(47,161)	11,974
Commitments and contingencies				
Shareholders' equity:				
Common stock	1	—	—	1
Additional paid-in capital	377,529	236,944	(236,944)	377,529
Retained earnings	68,380	32,110	(32,110)	68,380
Treasury stock, at cost	(24,167)	—	—	(24,167)
Total shareholders' equity	421,743	269,054	(269,054)	421,743
Total liabilities and shareholders' equity	$1,423,339	$322,217	$(321,462)	$1,424,094

(1) Began operations on May 1, 2010

Condensed Consolidating Statement of Income for the Twelve Months Ended December 31, 2010

	Parent Company	Guarantor Subsidiary (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Revenues	$608,600	$97,183	$ —	$705,783
Operating costs and expenses:				
Lease operating expenses	152,534	17,136	—	169,670
Production taxes	1,194	—	—	1,194
Gathering and transportation	15,338	1,146	—	16,484
Depreciation, depletion and amortization	241,105	27,310	—	268,415
Asset retirement obligation accretion	25,122	563	—	25,685
General and administrative expenses	51,662	1,628	—	53,290
Derivative loss	4,256	—	—	4,256
Total costs and expenses	491,211	47,783	—	538,994
Operating income	117,389	49,400	—	166,789
Earnings of affiliates	32,110	—	(32,110)	—
Interest expense:				
Incurred	43,101	—	—	43,101
Capitalized	(5,395)	—	—	(5,395)
Interest income	710	—	—	710
Income before income tax expense	112,503	49,400	(32,110)	129,793
Income tax expense (benefit)	(5,389)	17,290	—	11,901
Net income	$117,892	$32,110	$(32,110)	$117,892

(1) Began operations on May 1, 2010

Condensed Consolidating Statement of Cash Flows for the Twelve Months Ended December 31, 2010

	Parent Company	Guarantor Subsidiary (1)	Eliminations	Consolidated W&T Offshore, Inc.
	(In thousands)			
Operating activities:				
Net income	$ 117,892	$ 32,110	$ (32,110)	$ 117,892
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion	266,227	27,873	—	294,100
Amortization of debt issuance costs and discount on indebtedness	1,338	—	—	1,338
Share-based compensation related to restricted stock issuances	5,533	—	—	5,533
Derivative loss	4,256	—	—	4,256
Cash payments on derivative settlements	874	—	—	874
Deferred income taxes	(5,511)	(2,755)	—	(8,266)
Earnings of affiliates	(32,110)	—	32,110	—
Changes in operating assets and liabilities:				
Oil and natural gas receivables	4,556	(29,489)	—	(24,933)
Joint interest and other receivables	25,897	—	—	25,897
Insurance receivables	54,873	—	—	54,873
Income taxes	84,023	20,044	—	104,067
Prepaid expenses and other assets	4,536	(47,160)	47,160	4,536
Asset retirement obligations	(87,166)	—	—	(87,166)
Accounts payable and accrued liabilities	(35,278)	3,393	—	(31,885)
Other liabilities	50,816	—	(47,160)	3,656
Net cash provided by operating activities	460,756	4,016	—	464,772
Investing activities:				
Acquisition of property interests	—	(236,944)	—	(236,944)
Investment in oil and natural gas properties and equipment	(174,693)	(4,016)	—	(178,709)
Proceeds from sales of oil and natural gas properties and equipment	1,420	—	—	1,420
Investment in subsidiary	(236,944)	—	236,944	—
Purchases of furniture, fixtures and other	(760)	—	—	(760)
Net cash used in investing activities	(410,977)	(240,960)	236,944	(414,993)
Financing activities:				
Borrowings of long-term debt	627,500	—	—	627,500
Repayments of long-term debt	(627,500)	—	—	(627,500)
Dividends to shareholders	(59,609)	—	—	(59,609)
Other	298	—	—	298
Investment from parent	—	236,944	(236,944)	—
Net cash provided by (used in) financing activities	(59,311)	236,944	(236,944)	(59,311)
Increase in cash and cash equivalents	(9,532)	—	—	(9,532)
Cash and cash equivalents, beginning of period	38,187	—	—	38,187
Cash and cash equivalents, end of period	$ 28,655	$ —	$ —	$ 28,655

(1) Began operations on May 1, 2010

21. Supplemental Oil and Gas Disclosures—UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the United States, with substantially all of those reserves located in the Gulf of Mexico. Therefore the following disclosures about our costs incurred, results of operations and proved reserves are on a total-company basis.

Capitalized Costs

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

	December 31,		
	2010	2009	2008
Net capitalized cost:			
Proved oil and natural gas properties and equipment	$ 5,130.9	$ 4,637.2	$ 4,580.1
Unproved oil and natural gas properties and equipment	94.7	95.5	104.6
Accumulated depreciation, depletion and amortization	(4,009.9)	(3,743.3)	(3,210.4)
	$ 1,215.7	$ 989.4	$ 1,474.3

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, 2010, by the year in which the costs were incurred (in millions):

	Total	2010	2009	2008	Prior to 2008
Costs excluded by year incurred:					
Acquisition costs	$45.7	$ —	$ —	$ —	$45.7
Capitalized interest	19.7	4.9	4.3	4.5	6.0
	$65.4	$4.9	$4.3	$4.5	$51.7

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, 2010, 2009 and 2008 (in millions):

	Year Ended December 31,		
	2010	2009	2008
Costs incurred (1):			
Proved property acquisitions	$277.3	$ 17.5	$139.0
Development	158.3	142.9	373.4
Exploration (2) (3)	70.8	101.6	357.2
Unproved property acquisitions (4)	19.7	12.2	21.2
	$526.1	$274.2	$890.8

(1) Includes additions (reductions) to our ARO of $106.1 million, ($6.0) million and $111.1 million during the years ended December 31, 2010, 2009 and 2008, respectively, associated with acquisitions, liabilities incurred and revisions of estimates. Refer to Note 5.
(2) Includes seismic costs of approximately $5.8 million, $6.6 million and $14.5 million incurred during the years ended December 31, 2010, 2009 and 2008, respectively.
(3) Includes geological and geophysical costs charged to expense of $4.3 million, $4.1 million and $4.7 million during the years ended December 31, 2010, 2009 and 2008, respectively.
(4) The amounts for 2010, 2009 and 2008 include capitalized interest associated with properties classified as unproved at December 31, 2010, 2009 and 2008, respectively.

Depreciation, depletion, amortization and accretion expense

The following table presents our depreciation, depletion, amortization and accretion ("DD&A") expense per Mcfe of products sold.

	Year Ended December 31,		
	2010	2009	2008
Depreciation, depletion, amortization and accretion per Mcfe . . .	$3.38	$3.61	$5.33

As discussed below, DD&A expense for 2009 increased by approximately $7.6 million ($0.08 per Mcfe) as a result of our adoption of certain amendments to the *Extractive Activities—Oil and Gas* Topic of the Codification.

Oil and Natural Gas Reserve Information

Effective for our annual reporting period ended December 31, 2009, we adopted certain amendments to the *Extractive Activities—Oil and Gas* topic of the Codification that updated and aligned the FASB's reserve estimation and disclosure requirements for oil and natural gas companies with the reserve estimation and disclosure requirements that were adopted by the SEC in December 2008. In accordance with the new rules, we use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than end-of-period commodity prices, when estimating quantities of proved reserves. Similarly, the prices used to calculate the standardized measure of discounted future cash flows and prices used in the ceiling test impairment were changed from end-of-period commodity prices to the 12-month average commodity prices. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years. As the rules are effective for December 31, 2009 and were not applied retroactively, the data for 2008 and prior may not be comparable to the data for 2009 and 2010. In addition to the oil and gas reserve information, the amendments impacted our financial position and the results of operations as they affected our determination of DD&A expense and the calculations used in determining impairment under the ceiling test rules. The amendments did not have an impact to our cash flows.

For the year ended December 31, 2009, the following items were affected by the change in the rules. The initial application of these rules resulted in the removal of 23.2 Bcfe in the year ended December 31, 2009 of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87

per MMBtu for natural gas). The impact on our DD&A expense for 2009 related to the adoption of these amendments to the Codification was an approximate $7.6 million ($0.08 per Mcfe) increase in DD&A.

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 10% 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 estimated quantities of our net proved, proved developed and proved undeveloped oil (including natural gas liquids) and natural gas reserves, virtually all of which are located offshore in the Gulf of Mexico. These reserve estimates exclude insignificant royalties and interests owned by the Company due to the unavailability of such information.

			Total Equivalent Reserves	
	Oil and NGLs (MMBbls) (1)	Natural Gas (Bcf) (1)	Natural Gas Equivalent (Bcfe) (2)	Barrel Equivalent (MMBoe) (2)
Proved reserves as of December 31, 2007	51.0	332.8	638.8	106.5
Revisions of previous estimates (3)	(12.1)	(84.2)	(157.5)	(26.3)
Extensions and discoveries (4)	3.7	25.0	47.2	7.9
Purchase of minerals in place (5)	8.3	10.4	60.5	10.1
Production	(7.0)	(56.1)	(97.9)	(16.3)
Proved reserves as of December 31, 2008	43.9	227.9	491.1	81.9
Revisions of previous estimates (6)	(2.1)	(13.0)	(25.4)	(4.3)
Extensions and discoveries (7)	1.5	14.5	23.4	3.9
Purchase of minerals in place	—	0.4	0.7	0.1
Sales of reserves (8)	(1.9)	(12.4)	(24.0)	(4.0)
Production	(7.2)	(51.6)	(94.8)	(15.8)
Proved reserves as of December 31, 2009	34.2	165.8	371.0	61.8
Revisions of previous estimates (9)	1.0	14.6	20.2	3.4
Extensions and discoveries (10)	1.7	19.1	29.2	4.9
Purchase of minerals in place (11)	8.4	101.5	152.0	25.3
Production	(7.1)	(44.7)	(87.0)	(14.5)
Proved reserves as of December 31, 2010	38.2	256.3	485.4	80.9
Year-end proved developed reserves:				
2010	27.0	229.1	391.3	65.2
2009	23.7	141.3	283.5	47.3
2008	24.6	186.3	334.1	55.7
Year-end proved undeveloped reserves:				
2010	11.2	27.2	94.1	15.7
2009	10.5	24.5	87.5	14.5
2008	19.3	41.6	157.0	26.2

(1) Estimated reserves as of December 31, 2007 and 2008 are based on end-of-period commodity prices in accordance with the previous definitions and guidelines of the SEC and the FASB in effect on those respective dates. Estimated reserves as of December 31, 2009 and 2010 are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for those years in accordance with current definitions and guidelines set forth by the SEC and the FASB.

(2) One billion cubic feet equivalent (Bcfe) and one million barrel equivalent (MMBoe) 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). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. Similarly, the price per barrel for oil and natural gas liquids may differ significantly from the price per Boe for natural gas.

(3) Revisions of previous estimates can result from changes in commodity prices, changes in the performance of our properties and changes in the regulations which govern the estimation and reporting of reserves applicable to oil and natural gas companies. 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.

(4) 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.

(5) The amount for 2008 relates to volumes attributable to the purchase of the remaining working interest in Ship Shoal 349 field from Apache.

(6) Revisions for 2009 included decreases attributable to the new reserve reporting requirements for oil and natural gas companies enacted by the SEC and the FASB, which became effective for annual reporting periods ending on or after December 31, 2009. The initial application of these rules resulted in the removal of 23.2 Bcfe of proved undeveloped reserves associated with two of our fields for which our plan of development was not within five years from when the reserves were initially recorded, as required. In addition, positive revisions of 27.5 Bcfe that would have resulted from using end-of-period commodity prices as of December 31, 2009 ($76.00 per barrel for oil and natural gas liquids and $5.79 per MMBtu for natural gas) were offset by 25.1 Bcfe, the impact of which is attributable to the new requirement that oil and natural gas reserves are to be measured using the 12-month average commodity price for each product ($57.65 per barrel for oil and natural gas liquids and $3.87 per MMBtu for natural gas). Also included in the revisions of previous estimates for 2009 are negative revisions of 4.7 Bcfe due to performance.

(7) The majority of these volumes are attributable to extensions and discoveries resulting from our participation in the drilling of eight successful exploratory wells in 2009, all of which were on the conventional shelf.

(8) In the second quarter of 2009, we sold one of our fields in Louisiana state waters, and in the fourth quarter of 2009, we sold 36 non-core oil and natural gas fields in the Gulf of Mexico, subject to the terms of the purchase and sale agreements. For additional details about these transactions, refer to Note 2.

(9) Includes revisions due to price of 17.5 Bcfe

(10) Includes discoveries of 21.9 Bcfe primarily in the Main Pass 108, Main Pass 98 and Main Pass 283 fields and extensions of 7.2 Bcfe primarily in the Main Pass 283 field.

(11) Primarily due to the properties acquired from Total and the properties acquired from Shell

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 natural 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 the unweighted average of first-day-of-the-month commodity prices for the years ended December 31, 2010 and 2009 and period-end commodity prices for the year ended December 31, 2008. All prices are adjusted by lease for quality, transportation fees, energy content and regional price differentials. The unweighted average commodity prices related to proved reserves of natural gas approximated $4.38 per Mcf and for oil and natural gas liquids approximated $75.96 per barrel at December 31, 2010. The unweighted average commodity prices related to proved reserves of natural gas approximated $3.80 per Mcf and for oil and natural gas liquids approximated $53.91 per barrel at December 31, 2009. At December 31, 2008, the end-of-period prices related to proved reserves of natural gas approximated $6.17 and for oil and natural gas liquids approximated $37.71. Future production, development costs and ARO are based on costs in effect at the end of each of the respective years 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, future changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2011 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,		
	2010	2009	2008
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 3,953,655	$2,474,260	$ 3,059,353
Future costs:			
Production	(1,011,552)	(604,794)	(667,132)
Development	(243,570)	(212,835)	(396,103)
Dismantlement and abandonment	(520,490)	(496,540)	(751,324)
Income taxes	(495,696)	(186,101)	(136,471)
Future net cash inflows before 10% discount	1,682,347	973,990	1,108,323
10% annual discount factor	(503,275)	(313,594)	(346,641)
	$ 1,179,072	$ 660,396	$ 761,682

	Year Ended December 31,		
	2010	2009	2008
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 660,396	$ 761,682	$ 2,112,275
Sales and transfers of oil and gas produced, net of production costs	(521,551)	(386,331)	(960,918)
Net changes in price, net of future production costs	367,575	(34,841)	(1,572,781)
Extensions and discoveries, net of future production and development costs	143,612	98,087	259,952
Changes in estimated future development costs	(59,124)	144,590	156,720
Previously estimated development costs incurred	97,188	224,802	275,344
Revisions of quantity estimates	94,735	(86,600)	(486,811)
Accretion of discount	68,862	78,789	272,483
Net change in income taxes	(221,226)	(32,394)	752,463
Purchases of reserves in-place	624,302	(9,927)	135,761
Sales of reserves in-place	—	(205,691)	—
Changes in production rates due to timing and other	(75,697)	108,230	(182,806)
Net increase (decrease) in standardized measure	518,676	(101,286)	(1,350,593)
Standardized measure, end of year	$ 1,179,072	$ 660,396	$ 761,682

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 SEC 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, 2010 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 are 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, 2010, 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, 2010, 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, 2010 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 4A 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)
2.2	Purchase and Sale Agreement between Total E&P USA Inc. and W&T Offshore, Inc. effective January 1, 2010. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed on May 3, 2010)

Exhibit Number	Description
2.3	Asset Purchase Agreement between Shell Offshore, Inc., as Seller, and W&T Offshore, Inc. and W&T Energy VI, LLC as Purchasers, dated November 3, 2010. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed November 9, 2010)
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*	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)
10.3*	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)
10.4*	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))
10.5*	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))
10.6*	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))
10.7*	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)
10.8	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))
10.9	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)

Exhibit Number	Description
10.10	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)
10.11	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)
10.12*	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)
10.13*	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)
10.14	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)
10.15	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)
10.16	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)
10.17*	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)
10.18	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)
10.19*	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)
10.20*	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)
10.21*	Seventh Amendment to Third Amended and Restated Credit Agreement, dated May 4, 2009. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.22*	Second Amendment to W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference from Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed April 17, 2009)
10.23*	Third Amendment to W&T Offshore, Inc. Long-Term Incentive Compensation Plan. (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed April 17, 2009)

Exhibit Number	Description
10.24*	Indemnification and Hold Harmless Agreement, dated August 5, 2009, by and between B. Frank Stanley and the Company. (Incorporated by reference to Exhibit 10.8 of the Company's Registration Statement on Form S-1, filed May 1, 2004 (File No. 333-115103))
10.25*	W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan. (Incorporated by reference from Appendix A to the Company's Definitive Proxy Statement on Schedule 14A, filed April 2, 2010)
10.26*	Resignation Agreement dated as of July 1, 2010 between W. Reid Lea and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed July 8, 2010)
10.27*	Form of Employment Agreement for Executive Officers other than the Chief Executive Officer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed August 6, 2010)
10.28*	Employment Agreement for Tracy W. Krohn. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on November 5, 2010)
10.29*	Form of the Executive Annual Incentive Award Agreement for Fiscal Year 2010. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010)
10.30*	Form of the Executive Restricted Stock Unit Agreement. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010)
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.
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.

* 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.

Boe. Barrel of oil equivalent.

BOEMRE. Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service), is the federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf

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.

Deterministic estimate. Refers to a method of estimation whereby a single value for each parameter in the reserves calculation is used in the reserves estimation procedure.

Developed reserves. Oil and natural gas reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A project by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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 that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. Refers to a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

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 a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

Extension well. A well drilled to extend the limits of 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.

MBoe. One thousand barrels of oil equivalent.

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.

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. Outer continental shelf

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

Probabilistic estimate. Refers to a method of estimation whereby the full range of values that could reasonably occur for each unknown parameter in the reserves estimation procedure is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A well that is found to have economically producible hydrocarbons.

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, “existing economic conditions” include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) 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.

PV-10 value. A term used in the industry that is not a defined term in generally accepted accounting principles. We define PV-10 as the present value of estimated future net revenues of estimated proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs. PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

Reasonable certainty. When deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities of hydrocarbons will be recovered. When probabilistic methods are used, reasonable certainty means at least a 90% probability that the quantities of hydrocarbons actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience, engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

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

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Estimated remaining quantities of oil, natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering the oil, natural gas or related substances to market, and all permits and financing required to implement the project.

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.

Supra-salt. A geological layer lying above the salt layer

Undeveloped reserves. Oil and natural gas reserves of any category 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved 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 4, 2011.

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 4, 2011.

/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
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
/s/ B. FRANK STANLEY **B. Frank Stanley**	Director

Company Information

Company Profile

W&T Offshore is an independent oil and natural gas company focused primarily in the Gulf of Mexico, including exploration in the deepwater and deep shelf regions, where it has developed significant technical expertise. W&T has grown through acquisition, exploitation and exploration and holds working interests in approximately 67 fields, in federal and state waters and a majority of its daily production is derived from wells it operates.

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 February 25, 2011, there were 298 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 April 26, 2011, at 9:00 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 2009, filed with the Securities and Exchange Commission, is available from the Company. Requests for investor-related information should be directed to Janet Yang, Finance Manager, 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 301 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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